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May 1, 2023

BY ELECTRONIC DELIVERY

Bernard Logan, Clerk
Document Control Center
State Corporation Commission
1300 E. Main Street, Tyler Bldg., 1st Fl.
Richmond, VA 23219

Commonwealth of Virginia, ex rel. State Corporation Commission,
In re: Virginia Electric and Power Company's 2023 Integrated Resource Plan
filing pursuant to Va. Code § 56-597 et seq.
Case No. PUR-2023-00066

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-captioned proceeding the 2023 Integrated Resource Plan (the "2023 Plan") of Virginia Electric and Power Company (the "Company") filed pursuant to § 56-597 *et seq*. of the Code of Virginia ("Va. Code") and the Integrated Resource Planning Guidelines adopted by the State Corporation Commission of Virginia ("Commission") in Case No. PUE-2008-00099 ("Guidelines"). As required by the Commission, a reference index is enclosed that identifies the sections of the 2023 Plan that comply with the Va. Code, the Guidelines, and the requirements of relevant prior Commission orders. Also enclosed is a copy of the Company's proposed notice in this proceeding pursuant to Section E of the Guidelines.

Along with the 2023 Plan, the Company is filing two addenda under separate cover. Virginia Addendum 1 contains the detailed results of the Virginia consolidated bill analysis, and Virginia Addendum 2 contains the Grid Transformation Plan Document. In addition to the addenda, the Company is contemporaneously filing its Motion for Entry of a Protective Order and Additional Protective Treatment for Extraordinarily Sensitive Information under separate cover where the Company is proposing an additional process for the first time to reduce the administrative burden on the Commission, the Commission Staff, and parties for challenges to confidentiality designations.

Separate from these filings with the Commission, the Company is providing Commission Staff with the Guidelines schedules associated with the 2023 Plan in electronic format pursuant to Section E of the Guidelines, and is providing a copy of the 2023 Plan to members of the General Assembly pursuant to Va. Code § 56-599.

To the extent the Commission modifies Rule 260 of the Rules of Practice and Procedure, 5 VAC 5-20-260, in its procedural order for this proceeding related to the deadline to respond to discovery requests, the Company respectfully requests that the Commission allow the Company, Staff, and all respondents at least five (5) *business* days to respond or object to interrogatories or requests for production of documents after the receipt of same. Requiring the response time to be in *business* days instead of *calendar* days allows for intervening weekends and holidays to not be counted and allows the Company and parties time for more fulsome and complete responses. Granting this request will not prejudice Staff or any party in this proceeding and will allow sufficient time to respond to what the Company expects to be a significant amount of discovery over the next several months.

Please do not hesitate to contact me if you have any questions regarding this filing.

Very truly yours,

<u>/s/ Vishwa B. Link</u>

Vishwa B. Link

Enclosures

cc: William H. Chambliss, Esq.
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Citation	Requirement	2023 Plan Section
Va. Code § 56-598 (1)	An IRP should: 1. Integrate, over the planning period, the electric utility's forecast of demand for electric generation supply with recommended plans to meet that forecasted demand and assure adequate and sufficient reliability of service, including, but not limited to: a. Generating electricity from generation facilities that it currently operates or intends to construct or purchase; b. Purchasing electricity from affiliates and third parties; and c. Reducing load growth and peak demand growth through cost-effective demand reduction programs.	**Section 2.2** Alternative Plans
Va. Code § 56-598 (2)	An IRP should: 2. Identify a portfolio of electric generation supply resources, including purchased and self-generated electric power, that: a. Consistent with § 56-585.1, is most likely to provide the electric generation supply needed to meet the forecasted demand, net of any reductions from demand side programs, so that the utility will continue to provide reliable service at reasonable prices over the long term; and b. Will consider low cost energy/capacity available from short-term or spot market transactions, consistent with a reasonable assessment of risk with respect to both price and generation supply availability over the term of the plan.	**Section 2.2** Alternative Plans **Section 5.5.3** Third-Party Market Alternatives
Va. Code § 56-598 (3)	An IRP should: 3. Reflect a diversity of electric generation supply and cost-effective demand reduction contracts and services so as to reduce the risks associated with an over-reliance on any particular fuel or type of generation demand and supply resources and be consistent with the Commonwealth's energy policies as set forth in § 67-102.	**Section 2.2** Alternative Plans
Va. Code § 56-598 (4)	An IRP should: 4. Include such additional information as the Commission requests pertaining to how the electric utility intends to meets its obligation to provide electric generation service for use by its retail customers over the planning period.	**2023 Plan** Reference Index
Va. Code § 56-599 (A)	Each electric utility shall file an updated integrated resource plan by July 1, 2015. Thereafter, each electric utility shall file an updated integrated resource plan by May 1, in each year immediately preceding the year the utility is subject to a triennial review filing. A copy of each integrated resource plan shall be provided to the Chairmen of the House and Senate Committees on Commerce and Labor and to the Chairman of the Commission on Electric Utility Regulation.	**2023 Plan**
Va. Code § 56-599 (A)	All updated integrated resource plans shall comply with the provisions of any relevant order of the Commission establishing guidelines for the format and contents of updated and revised integrated resource plans. Each integrated resource plan shall consider options for maintaining and enhancing rate stability, energy independence, economic development including retention and expansion of energy-intensive industries, and service reliability.	**2023 Plan** Reference Index
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 1. Entering into short-term and long-term electric power purchase contracts.	**Section 2.2** Alternative Plans **Section 5.5** Future Supply-Side Generation Resources
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 2. Owning and operating electric power generation facilities.	**Section 2.2** Alternative Plans **Section 5.5** Future Supply-Side Generation Resources
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 3. Building new generation facilities.	**Section 2.2** Alternative Plans **Section 5.5** Future Supply-Side Generation Resources
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 4. Relying on purchases from the short term or spot markets.	**Section 2.2** Alternative Plans **Section 5.5** Future Supply-Side Generation Resources
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 5. Making investments in demand-side resources, including energy efficiency and demand-side management services;	**Section 2.2** Alternative Plans **Chapter 6** Generation - Demand-Side Management
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 6. Taking such other actions, as the Commission may approve, to diversify its generation supply portfolio and ensure that the electric utility is able to implement an approved plan;	**Section 2.2** Alternative Plans
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 7. The methods by which the electric utility proposes to acquire the supply and demand resources identified in its proposed integrated resource plan;	**Section 2.2** Alternative Plans
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 8. The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities;	**Section 1.2** Significant Federal Legislation **Section 1.10** Other Legislative Developments **Section 5.2.3** Environmental Regulations
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 9. The 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;	**Section 2.4** NPV Results **Section 2.6** Sensitivity Analyses
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 10. Long-term electric distribution grid planning and proposed electric distribution grid transformation projects; and	**Chapter 8** Distribution **Appendix 8A** 2023 IDP Roadmap **Va. Addendum 2** GT Plan Document

Citation	Requirement	2023 Plan Section
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 11. Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity.	**Chapter 6** Generation - Demand-Side Management
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 12. Developing a long-term plan to integrate new energy storage facilities into existing generation and distribution assets to assist with grid transformation	**Section 4.8** Storage-Related Assumptions **Section 5.5.1** Supply-Side Resource Options **Section 8.5** Battery Storage Pilot Program
Va. Code § 56-599 (C)	As part of preparing any integrated resource plan pursuant to this section, each utility shall conduct a facility retirement study for owned facilities located in the Commonwealth that emit carbon dioxide as a byproduct of combusting fuel and shall include the study results in its integrated resource plan. Upon filing the integrated resource plan with the Commission, the utility shall contemporaneously disclose the study results to each planning district commission, county board of supervisors, and city and town council where such electric generation unit is located, the Department of Mines, Minerals and Energy, the Department of Housing and Community Development, the Virginia Employment Commission, and the Virginia Council on Environmental Justice. The disclosure shall include (i) the driving factors of the decision to retire and (ii) the anticipated retirement year of any electric generation unit included in the plan. Any electric generating facility with an anticipated retirement date that meets the criteria of § 45.1-394.1 shall comply with the public disclosure requirements therein.	Not Applicable
Chapter 296 Enactment Clause 12	That any Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, shall consider in its integrated resource plan next filed after July 1, 2018, either as a demand-side energy efficiency measure or a supply-side generation alternative, whether the construction or purchase of one or more generation facilities with at least one megawatt of generating capacity, having a measurable aggregate rated capacity of 200 megawatts by 2024, that use combined heat and power or waste heat to power and are located in the Commonwealth, are in the customer interest. For purposes of this analysis, the total efficiency, including the use of thermal energy, for eligible combined heat and power facilities must meet or exceed 65 percent (Lower Heating Value). The assumed efficiency of waste heat to power systems that do not burn any supplemental fuel and use only waste heat as a fuel source is 100 percent. As used in this enactment, "waste heat to power" means a system that generates electricity through the recovery of a qualified waste heat resource and "qualified waste heat resource" means (i) exhaust heat or flared gas from an industrial process that does not have, as its primary purpose, the production of electricity and (ii) a pressure drop in any gas for an industrial or commercial process.	**Section 5.5.1** Supply-Side Resource Options
Chapter 296 Enactment Clause 18	That as part of its integrated resource plans filed between 2019 and 2028, any Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, shall incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; reduction in emissions; and reduction in the utility's carbon intensity. Considerations shall include analysis of the following: energy efficiency programs for low-income customers in alignment with billing and credit practices; energy efficiency programs that reflect policies and regulations related to customers with serious medical conditions; programs specifically focused on low-income customers, occupants of multifamily housing, veterans, elderly, and disabled customers; options for combining distributed generation, energy storage, and energy efficiency for residential and small business customers; the extent that electricity rates account for the amount of customer electricity bills in the Commonwealth and how such extent in the Commonwealth compares with such extent in other states, including a comparison of the average retail electricity price per kWh by rate class among all 50 states and an analysis of each state's primary fuel sources for electricity generation, accounting for energy efficiency, heating source, cooling load, housing size, and other relevant factors; and other issues as may seem appropriate.	**Section 6.6** GTSA Energy Efficiency Analysis **Appendix 6N** DNV National Comparison Analysis
Guideline (A)	In order to understand the basis for the utility's plan, the IRP filing shall include a narrative summary detailing the underlying assumptions reflected in its forecast as further described in the guidelines. To better follow the utility's planning process, the narrative shall include a description of the utility's rationale for the selection of any particular generation addition or demand-side management program to fulfill its forecasted need. Such description should include the utility's evaluation of its purchase options and cost/benefit analyses for each resource option to confirm and justify each resource option it has chosen. Such narrative shall also describe the planning process including timelines and appropriate reviews and/or approvals of the utility's plan. For members of PJM Interconnection, LLC ("PJM"), the narrative should describe how the IRP incorporates the PJM planning and implementation processes and how it will satisfy PJM load obligations.	**Chapter 4** Generation - Planning Assumptions
Guideline (A)	These guidelines also include sample schedules to supplement this narrative discussion and assist the utilities in developing a tabulation of the utility's forecast for at least a 15-year period and identify the projected supply-side or demand-side resource additions and solutions to adequately and reliably meet the electricity needs of the Commonwealth. This tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the same period. These guidelines also direct that all IRP filings include information to comparably evaluate various supply-side technologies and demand-side programs and technologies on an equivalent basis as more fully described below in Section F(7).	See References for Guideline (F)(7) and Schedules
Guideline (C)(1)	1. Forecast. A three-year historical record and a 15-year forecast of the utility's native load requirements, the utility's PJM load obligations if appropriate, and other system capacity or firm energy obligations for each peak season along with the supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced.	**Section 2.2** Alternative Plans **Section 4.1** Load Forecast **Appendix 2A** Capacity, Energy, and RECs for Alternative Plans A, B, C, D, and E **Appendix 4H** Projected Summer & Winter Peak Load & Energy Forecast for Plan B **Appendix 4I** Required Reserve Margin for Plan B

Citation	Requirement	2023 Plan Section
Guideline (C)(2)	2. Option analyses. A comprehensive analysis of all existing and new resource options (supply- and demand-side), including costs, benefits, risks, uncertainties, reliability, and customer acceptance where appropriate, considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, at the lowest reasonable cost, over the planning period.	**Section 5.5** Future Supply-Side Generation **Section 6.7** Overall DSM Assessment
Guideline (C)(2)(a)	a. Purchased Power - assess the potential costs and benefits of purchasing power from wholesale power suppliers and power marketers to supply it with needed capacity and describe in detail any decision to purchase electricity from the wholesale power market.	**Section 4.2** Capacity Market Assumptions
Guideline (C)(2)(b)	b. Supply-side Energy Resources - assess the potential costs and benefits of reasonably available traditional and alternative supply-side energy resource options, including, but not limited to technologies such as, nuclear, pulverized coal, clean coal, circulating fluidized bed, wood, combined cycle, integrated gasification combined cycle, and combustion turbine, as well as renewable energy resources such as those derived from sunlight, wind, falling water, sustainable biomass, energy from waste, municipal solid waste, wave motion, tides, and geothermal power.	**Section 5.5** Future Supply-Side Generation
Guideline (C)(2)(c)	c. Demand-side Options - assess the potential costs and benefits of programs that promote demand-side management. For purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options.	**Chapter 6** Generation - Demand-Side Management
Guideline (C)(2)(d)	d. Evaluation of Resource Options - analyze potential resource options and combinations of resource options to serve system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction or implementation costs, transmission and distribution costs, environmental impacts and compliance costs.	**Section 2.2** Alternative Plans **Section 2.6** Sensitivity Analyses
Guideline (C)(3)	3. Data availability. To the extent the information requested is not currently available or is not applicable, the utility will clearly note and explain this in the appropriate location in the plan, narrative, or schedule.	As Applicable
Guideline (D)	Each utility shall provide a narrative summary detailing the major trends, events, and/or conditions reflected in the forecasted data submitted in response to these guidelines.	**Chapter 1** Significant Development and Context for the Integrated Planning Process
Guideline (D)(1)	1. Discussion regarding the forecasted peak load obligation and energy requirements. PJM members should also discuss the relationship of the utility's expected non-coincident peak and its expected PJM related load obligations.	**Section 4.1** Load Forecast
Guideline (D)(2)	2. Discussion regarding company goals and plans in response to directives of Chapters 23 and 24 of Title 56 of the Code of Virginia, including compliance with energy efficiency, energy conservation, demand-side and response programs, and the provision of electricity from renewable energy resources.	**Executive Summary** **Section 2.2** Alternative Plans **Section 5.4.1** Solar, Onshore Wind, and Energy Storage **Appendix 3A** Generation Under Construction **Appendix 6A** Description of Active DSM Programs **Appendix 6F** Description of Proposed DSM Programs
Guideline (D)(3)	3. Discussion regarding the complete planning process, including timelines, assumptions, reviews, approvals, etc., of the company's plans. For PJM members, the discussion should also describe how the IRP integrates into the complete planning process of PJM.	**Chapter 4** Generation - Planning Assumptions
Guideline (D)(4)	4. Discussion of the critical input assumptions to determine the load forecast and expected changes in load growth including factors such as energy conservation, efficiency, load management, demand response, variations in customer class sizes, expected levels of economic activity, variations in fuel prices and appliance inventories, etc.	**Section 4.1** Load Forecast **Appendix 4M** Economic Assumptions
Guideline (D)(5)	5. Discussion regarding cost/benefit analyses and the results of such factors on this plan, including the methodology used to consider equal or comparable treatment afforded both the demand-side options and supply-side resources.	**Chapter 4** Generation - Planning Assumptions **Chapter 5** Generation - Supply-Side Resources **Chapter 6** Generation - Demand-Side Management
Guideline (D)(6)	6. Planned changes in operating characteristics such as unit retirements, unit uprates or derates, changes in unit availabilities, changes in capacity resource mix, changes in fuel supplies or transport, emissions compliance, unit performance, etc.	**Section 4.9** Gas Transportation Cost Assumptions **Section 5.2** Evaluation of Existing Generation **Appendix 5J** Potential Unit Retirements **Appendix 5K** Planned Changes to Existing Generation Units **Appendix 5L** Environmental Regulations
Guideline (D)(7)	7. Discussion regarding the effectiveness of the utility's IRP to meet its load obligations with supply-side and demand-side resources to enable the utility to provide reliable service at reasonable prices over the long term.	**Section 2.2** Alternative Plans **Section 2.4** NPV Results **Section 2.5** Virginia Consolidated Bill Analysis

Citation	Requirement	2023 Plan Section
Guideline (E)	By September 1, 2009, and every two years thereafter, each utility shall file with the Commission its then current integrated resource plan, which shall include all information required by these guidelines for the ensuing 15-year planning period along with the prior three-year historical period. The process and analyses shall be described in a narrative discussion and the results presented in tabular format using an EXCEL spreadsheet format, similar to the attached sample schedules, and be provided in both printed and electronic media. For those utilities that operate as part of a multi-state integrated power system, the schedules should be submitted for both the individual company and the generation planning pool of which the utility is a member. The top line stating the company name should indicate that the data reflects the individual utility company or the total system. For partial ownership of any facility, please provide the percent ownership and footnote accordingly	**2023 Plan**
Guideline (E)	Each filing shall include a five-year action plan that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP.	**Chapter 3** Short-Term Action Plan
Guideline (E)	If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures.	Motion for Protective Order
Guideline (E)	As § 56-599 E requires the giving of notice and an opportunity to be heard, each utility shall also include a copy of its proposed notice to be used to afford such an opportunity.	**2023 Plan** Proposed Notice
Guideline (F)(1)	1. Forecast of Load. The forecast shall include descriptions of the methods, models, and assumptions used by the utility to prepare its forecasts of its loads, requirements associated with the utility's PJM load obligation (MW) if appropriate, the utility's peak load (MW) and energy sales (MWh) and the variables used in the models	**Section 4.1** Load Forecast
Guideline (F)(1)(a)	a. The most recent three-year history and 15-year forecast of energy sales (kWh) by each customer class	**Appendix 4A** Total Sales by Customer Class (DOM LSE) (GWh) **Appendix 4B** Virgiinia Sales by Customer Class (DOM LSE) (GWh) **Appendix 4C** North Carolina Sales by Customer Class (DOM LSE) (GWh)
Guideline (F)(1)(b)	b. The most recent three-year history and 15-year forecast of the utility's peak load and the expected load obligation to satisfy PJM's coincident peak forecast if appropriate, and the utility's coincident peak load and associated noncoincident peak load for summer and winter seasons of each year (prior to any DSM), annual energy forecasts, and resultant reserve margins. During the forecast period, the tabulation shall also indicate the projected effects of incremental demand-side options on the forecasted annual energy and peak loads	**Appendix 4H** Projected Summer & Winter Peak Load & Energy Forecast for Plan B **Appendix 4I** Required Reserve Margin for Plan B
Guideline (F)(1)(c)	c. Where future resources are required, a description and associated characteristics of the option that the utility proposes to use to address the forecasted need	**Section 5.5** Future Supply-Side Generation
Guideline (F)(2)	2. Supply-side Resources. The forecast shall provide data for its existing and planned electric generating facilities (including planned additions and retirements and rating changes, as well as firm purchase contracts, including cogeneration and small power production) and a narrative description of the driver(s) underlying such anticipated changes such as expected environmental compliance, carbon restrictions, technology enhancements, etc.	**Chapter 1** Significant Developments and Context for Integrated Planning Process **Chapter 5** Generation - Supply-Side Resources **Appendix 5L** Environmental Regulations
Guideline (F)(2)(a)	a. Existing Generation. For existing units in service: i. Type of fuel(s) used ii. Type of unit (e.g., base, intermediate, or peaking) iii. Location of each existing unit iv. Commercial Operation Date v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW)) vi. Units to be placed in reserve shutdown or retired from service with expected date of shutdown or retirement and an economic analysis supporting the planned retirement or shutdown dates vii. Units with specific plans for life extension, refurbishment, fuel conversion, modification or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, expected return to service date, capacity rating upon return to service, a general description of work to be performed as well as an economic analysis supporting such plans for existing units viii. Major capital improvements such as the addition of scrubbers, shall be evaluated through the IRP analysis to assess whether such improvements are cost justified when compared to other alternatives, including retirement and replacement of such resources ix. Other changes to existing generating units that are expected to increase or decrease generation capability of such units.	**Section 5.2** Evaluation of Existing Generation **Appendix 5A** Existing Generation Units in Service **Appendix 5J** Potential Unit Retirements **Appendix 5K** Planned Changes to Existing Generation Units
Guideline (F)(2)(b)	b. Assessment of Supply-side Resources. Include the current overall assessment of existing and potential traditional and alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent IRP or annual report.	**Section 5.5** Future Supply-Side Generation

Citation	Requirement	2023 Plan Section
Guideline (F)(2)(b)(i)	i. For the currently operational or potential future supply-side energy resources included, provide information on the capacity and energy available or projected to be available from the resource and associated costs. The utility shall also provide this information for any actual or potential supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.	**Section 3.1** STAP - Generation **Appendix 5O** Renewable Resources for Plan B **Appendix 5P** Potential Supply-Side Resources for Plan B **Appendix 5Q** Summer Capacity Position for Plan B **Appendix 5R** Capacity Position for Plan B **Appendix 5S** Construction Forecast for Plan B
Guideline (F)(2)(b)(ii)	ii. For supply-side energy resources evaluated but rejected, a description of the resource; the potential capacity and energy associated with the resource; estimated costs and the reasons for the rejection of the resource.	**Section 5.5.1** Supply-Side Resource Options
Guideline (F)(2)(c)	c. Planned Generation Additions. A list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition: i. Type of conventional or alternative facility and fuel(s) used ii. Type of unit (e .g . baseload, intermediate, peaking) iii. Location of each planned unit, including description of locational benefits identified by PJM and/or the utility iv. Expected Commercial Operation Date v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW)) vi. Summaries of the analyses supporting such new generation additions, including its type of fuel and designation as base, intermediate, or peaking capacity vii. Estimated cost of planned unit additions to compare with demand-side options	**Section 5.3** Generation Under Construction **Section 5.4** Generation Resources Under Development **Appendix 3A** Generation under Construction **Appendix 3B** Planned Generation under Development **Appendix 6P** Comparison of Per MWh Costs of Selected Resources
Guideline (F)(2)(d)	d. Non-Utility Generation. A separate list of all non-utility electric generating facilities included in the lRP, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and contractual capacity (including any contract dispatch conditions or limitations), and the contractual start and expiration dates. The utility shall also indicate which facilities are included in their total supply of resources	**Section 5.1.3** Power Purchase Agreements **Appendix 5B** Other Generation Units
Guideline (F)(3)	3. Capacity Position. Provide a narrative discussion and tabulation reflecting the capacity position of the utility in relation to satisfying PJM's load obligation, similar to Schedule 16 of the attached schedules.	**Section 2.1** Capacity, Energy, and REC Position **Appendix 2A** Capacity, Energy, and RECs for Alternative Plans A, B, C, D, and E **Appendix 5Q** Summer Capacity Position for Plan B
Guideline (F)(4)	4. Wholesale Contracts for the Purchase and Sale of Power. A list of firm wholesale purchased power and sales contracts reflected in the plan, including the primary fuel type, designation as base, intermediate, or peaking capacity, contract capacity, location, commencement and expiration dates, and volume.	**Appendix 4K** Wholesale Power Sales Contracts
Guideline (F)(5)	5. Demand-side Options. Provide the results of its overall assessment of existing and potential demand-side option programs, including a descriptive summary of each analysis performed or used by the utility in its assessment and any changes to the methods and assumptions employed since its last IRP. Such descriptive summary, and corresponding schedules, shall clearly identify the total impact of each DSM program.	**Chapter 6** Generation - Demand-Side Management **Appendix 4L** Load Duration Curves **Appendix 6A** Description of Active DSM Programs **Appendix 6F** Description of Proposed Programs **Appendix 6O** Projected Savings Attributable to DSM Programs in 2028 **Appendix 6P** Comparison of Per MWh Costs of Selected Resources
Guideline (F)(6)	6. Evaluation of Resource Options. Provide a description and a summary of the results of the utility's analyses of potential resource options and combinations of resource options performed by it pursuant to these guidelines to determine its integrated resource plan. IRP filings should identify and include forecasted transmission interconnection and enhancement costs associated with specific resources evaluated in conjunction with the analysis of resource options.	**Section 4.7.5** Renewable Energy Interconnection and Integration Costs **Section 5.5** Future Supply-Side Resource Options
Guideline (F)(7)	7. Comparative Costs of Options. Provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-side options and demand-side options to permit comparison of such resources on equitable footing. Such data should be tabulated and at a minimum, reflect the resource's heat rate, variable and fixed operating maintenance costs, expected service life, overnight construction costs, fixed charged rate, and the basis of escalation for each component.	**Section 5.5.2** Levelized Busbar Costs / Levelized Cost of Energy **Appendix 5M** Tabular Results of Busbar **Appendix 5N** Busbar Assumptions **Appendix 6P** Comparison of Per MWh Costs of Selected Resources

Citation	Requirement	2023 Plan Section
Schedule 1	Peak load and energy forecast	**Appendix 4H** Projected Summer & Winter Peak Load & Energy Forecast for Plan B
Schedule 2	Generation output	**Appendix 5G** Energy Generation by Type for Plan B (GWh)
Schedule 3	System output mix	**Appendix 5H** Energy Generation by Type for Plan B (%)
Schedule 4	Seasonal capability	**Appendix 5R** Capacity Position for Plan B
Schedule 5	Seasonal load	**Appendix 4J** Summer and Winter Peak for Plan B
Schedule 6	Reserve margin	**Appendix 4I** Required Reserve Margin for Plan B
Schedule 7	Installed capacity	**Appendix 5F** Existing Capacity for Plan B
Schedule 8	Equivalent availability factor	**Appendix 5C** Equivalent Availability Factor for Plan B
Schedule 9	Net capactiy factor	**Appendix 5D** Net Capacity Factor
Schedule 10	Average heat rate	**Appendix 5E** Heat Rates for Plan B
Schedule 11	Renewable resources	**Appendix 5O** Renewable Resources for Plan B
Schedule 12	DSM programs	**Appendix 6D** Approved Programs Energy Savings for Plan B (MWh) (System Level) **Appendix 6I** Proposed Programs Energy Savings for Plan B (MWh) (System Level) **Appendix 6L** Future Undesignated EE Energy Savings for Plan B (MWh) (System Level)
Schedule 13	Unit size uprate and derate	**Appendix 5K** Planned Changes to Existing Generation Units
Schedule 14	Existing unit performance data	**Appendix 5A** Existing Generation Units in Service **Appendix 5B** Other Generation Units
Schedule 15	Planned unit performance data	**Appendix 3A** Generation under Construction **Appendix 3B** Planned Generation under Development **Appendix 5P** Potential Supply-Side Resources for Plan B
Schedule 16	Utility capacity position	**Appendix 5Q** Summer Capacity Position for Plan B
Schedule 17	Construction forecast	**Appendix 5S** Construction Forecast for Plan B
Schedule 18	Fuel data	**Appendix 4O** Delivered Fuel Data
Case No. PUR-2022-00124 Final Order at 8	The Commission finds reasonable Dominion's proposal to address---in its next IRP proceeding---(i) the load forecast, modeling, and planning implications of projecting (and conversely not projecting) a portion of data center load increases coming from ARBs, and (ii) its modeling assumption for energy efficiency beginning in 2026.	**Section 4.1.3** Energy Efficiency Adjustment **Section 9.3** Accelerated Renewable Energy Buyers
Case No. PUR-2022-00147 Final Order at 2	Model any impacts of the Inflation Reducation Act	**Section 4.6** Federal Tax Credit Assumptions
Case No. PUR-2020-00035 Final Order at 7, n.25	In future IRPs and updates, the Company shall, at a minimum, include the following sensitivities: (i) high and low PJM energy prices; (ii) high and low PJM capacity prices; (iii) high and low REC prices; (iv) high and low construction costs; (v) high and low fuel prices; (vi) high and low load forecast scenarios; and (vii) the impact of not meeting legislatively mandated energy efficiency savings targets.	**Section 2.6** Sensitivity Analyses
Case No. PUR-2020-00035 Final Order at 9	The Commission directs the Company to include in future IRPs and updates the up-to-date reliability analyses of the impacts of retiring traditional fossil generation and adding growing amounts of renewable energy resources on the Company's electric system.	**Section 2.3** Reliability Analyses of Alternative Plans **Section 7.5** Transmission System Reliability Analyses
Case No. PUR-2020-00035 Final Order at 9	In the future, the Company should also include one or more plans without [a 970 MW CT] "placeholder" additions to address reliability concerns for comparison purposes and to improve transparency in the Company's planning processes	**Section 2.2** Alternative Plans
Case No. PUR-2020-00035 Final Order at 10	We agree that it is appropriate to model retirements as part of the PLEXOS modeling; however, we will also require the Company, for the time being, to continue to file a separate retirement analysis comparable to the economic analysis performed in this case	**Section 5.2.1** Retirements

Citation	Requirement	2023 Plan Section
Case No. PUR-2020-00035 Final Order at 11, n.50	Staff recommended and the Company did not object to providing certain capacity-related information in future IRPs and updates, and we so direct as agreed by Staff and the Company. Includes: (i) the most recent PJM Dominion Zone coincident peak forecast; (ii) the most recent PJM Dominion Zone non-coincident peak forecast; (iii) versions of both aforementioned forecasts scaled down to the Dominion load serving entity level; (iv) each Company-owned generation unit interconnected at the transmission-level in the PJM Dominion Zone and the associated nameplate capacity; (v) all Company-owned units that have cleared the PJM capacity market or have capacity performance obligations; (vi) any notification to PJM of the Company's intention to retire or deactivate Company-owned units.	**Appendix 2B** Capacity Information Directed by the SCC
Case No. PUR-2020-00035 Final Order at 11-12 and n.53	In future IRPs and updates, the Company should study and report separately on its summer and winter capacity and energy needs, and its alternative plans' ability to meet those requirements. The Company should also give due consideration to market purchases during the winter from the PJM wholesale market, which remains a summer peaking entity; this consideration should include market purchases from merchant generators located within the Dominion Zone that are not subject to a transmission import capacity constraint.	**Section 2.1** Capacity, Energy, and REC Positions **Section 2.2** Alternative Plans **Appendix 2A** Capacity, Energy, and RECs for Alternative Plans A, B, C, D, and E **Appendix 5T** Winter Capacity for Alternative Plans A, B, C, D, and E
Case No. PUR-2020-00035 Final Order at 12	We direct the Company to continue to model energy efficiency targets after 2025	**Section 4.1.3** Energy Efficiency Adjustment
Case No. PUR-2020-00035 Final Order at 14 and n.56	Dominion proposes that future IRPs and updates include a least cost VCEA plan that would meet (i) applicable carbon regulations and (ii) the mandatory RPS Program requirements of the VCEA. For this plan, the Company proposes not to force the model to select any specific resource nor exclude any reasonable resource and allow the model to optimize the accompanying resource plan. Based on the record in this proceeding, we find this proposal to be reasonable at this time. While the Commission recognizes that certain build constraints may be necessary under certain circumstances, the reasonableness of any such build constraints will be subject to Commission review in future proceedings.	**Section 2.2** Alternative Plans **Section 4.11** Least-Cost Plan Assumptions
Case No. PUR-2020-00035 Final Order at 14-15	The Commission finds that the Company should address environmental justice in future IRPs and updates, as appropriate. As one example, the Company may consider the impact of unit retirement decisions on environmental justice communities or fenceline communities.	**Section 9.1** Environmental Justice
Case No. PUR-2020-00035 Final Order at 15-16	The Commission will require Dominion to file an updated bill analysis by plan in future IRPs and updates with the following modifications: • The Company shall provide bill impacts over the next ten years for the least cost VCEA plan, the Company's preferred plan, and any additional plans presented, including residential, small general service and large general service customer bills. Each update shall include an additional year of projections beyond 2030 as each year passes and should consistently be compared back to the actual bill as of May 1, 2020. • As proposed by Staff, the Company shall use class allocation factors and projected sales recently used to set rate adjustment clause rates in the bill analysis. • In addition to projections, the analysis shall include actual bill impact information as each year passes. For example, in the 2021 update filing, the Company would include the actual bill information as of December 31, 2020 in the bill analysis.	**Section 2.5** Virginia Consolidated Bill Analysis **Va. Addendum 1** Virginia Consolidated Bill Analysis
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 2. Continue to use the PJM load forecast, reduced by the energy efficiency spending requirement of Senate Bill 966 (Enactment Clause 15), both as an energy reduction and a supply resource, and separately identify the load associated with data centers.	**Section 4.1** Load Forecast
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 3. Model battery storage using the most updated cost estimates available.	**Section 4.8** Storage-Related Assumptions
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 4. Model compliance with the Regional Greenhouse Gas Initiative.	**Section 2.6** Sensitvity Analyses **Section 4.4** Commodity Price Assumptions
Case No. PUR-2018-00065 Final Order at 11 Case No. PUR-2018-00065 Dec. 2018 Order at 5, n. 14	In future IRPs, the Company shall: 5. Model gas transportation costs, including a reasonable estimate of fuel transportation costs (firm and interruptible transportation, if applicable) associated with all natural gas generation facilities as well as fuel commodity costs, consistent with the December 2018 Order	**Section 4.9** Gas Transportation Cost Assumptions
Case No. PUR-2018-00065 Final Order at 11-12 Case No. PUR-2018-00065 Order on Reconsideration at 5	In future IRPs, the Company shall: 7. Model future solar PV tracking resources using two alternative capacity factor values: (a) the actual capacity performance of Dominion's Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and (The Commission additionally noted that for the 2020 IRP, the Company should use the three-year average of calendar years 2017-2019. For those solar tracking facilities that have not been in service for three years, the Company should use the historic data that is available.) (b) 25%. In the Order on Reconsideration, the Commission approved the Compay's request to run one of the capacity factors contained in Directive #7 as a sensitivity; however, if the Company chooses to do so, it shall model the actual capacity performance of Dominion's Company-owned solar tracking fleet as the baseline assumption and use 25% as the sensitivity.	**Section 4.7.1** New Solar Resources
Case No. PUR-2018-00065 Final Order at 12	In future IRPs, the Company shall: 8. Systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects (Code § 56-599 B 10). For identified grid transformation projects, the Company shall include: (a) A detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) Detailed cost estimates of each proposed investment; (c) The benefits associated with each proposed investment; and (d) Alternatives considered for each proposed investment.	**Chapter 8** Distribution **Va. Addendum 2** GT Plan Document

Citation	Requirement	2023 Plan Section
Case No. PUR-2018-00065 Final Order at 12, n. 49	In future IRPs, the Company shall: 9. Provide a schedule identifying the Company's contribution towards meeting the 5,000 MW target identified in Code § 56-585.1:4, including (a) a list of each project in service or under construction; (b) the nameplate capacity of each project; (c) the actual or projected in-service date; (d) whether the project is Company-build or a third-party PPA; and (e) the cost recovery mechanism (e.g., fuel, base rates, RAC, ring-fence arrangement, etc.) The Company shall also maintain this information on an on-going basis and provide it to Staff upon request.	**Appendix 5I** Solar and Wind Generating Facilities
Case No. PUR-2018-00065 Final Order at 12	In future IRPs, the Company shall: 10. Provide, in addition to a list of planned transmission projects, the projected cost per transmission project and indicate whether or not each project is subject to PJM's Regional Transmission Expansion Planning process.	**Appendix 3C** List of Planned Transmission Projects during the Planning Period
Case No. PUE-2016-00049 Final Order at 3 Case No. PUE-2015-00035 Final Order at 18	Dominion shall continue to comply with all requirements directed in prior IRP orders, including the requirement to include an index that identifies the specific location(s) within the IRP that complies with each such requirement.	**2023 Plan** Reference Index
Case No. PUE-2015-00035 Final Order at 10	The Commission directs the Company to: continue to investigate the feasibility and cost of extending the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2	**Section 5.2.4** Nuclear License Extensions
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: include a more detailed analysis of market alternatives, especially third-party purchases that may provide long-term price stability, and includes, but is not limited to, wind and solar resources	**Section 4.7** Renewable Energy-Related Assumptions **Section 5.5.3** Third-Party Market Alternatives
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: examine wind and solar purchases at prices (including prices available through long-term purchase power agreements) and in quantities that are being seen in the market at the time the Company prepares its IRP filings	**Section 4.7** Renewable Energy-Related Assumptions **Section 5.5.3** Third-Party Market Alternatives
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: provide a comparison of the cost of purchasing power from wind and solar resources from third-party vendors versus self-build options, including off-shore and on-shore wind, with this comparison including information from a variety of third-party vendors	**Section 4.7** Renewable Energy-Related Assumptions **Section 5.5.3** Third-Party Market Alternatives
Case No. PUE-2015-00035 Final Order at 17	In future IRPs, Dominion shall: develop a plan for identifying, quantifying, and mitigating cost and integration issues associated with greater reliance on solar photovoltaic generation	**Section 4.7.5** Renewable Energy Interconnection and Integration Costs
Case No. PUE-2013-00088 Final Order at 4	Next, we find that in future IRP filings, the Company shall provide further analysis related to the construction of North Anna 3 and the future of Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, all of which have licenses that are scheduled to expire within the next thirty years.	**Section 5.2.4** Nuclear License Extensions **Section 5.4** Generation Resources Under Development
Case No. PUE-2013-00088 Final Order at 5-6	The Company shall also provide status updates on any discussions it engages in with the United States Nuclear Regulatory Commission on a possible extension for the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, in its future IRP and IRP update filings.	**Section 5.2.4** Nuclear License Extensions
Case No. PUE-2013-00088 Final Order at 8	Next, the Commission finds that in future IRP filings, Dominion Virginia Power should compare the cost of its demand-side management proposals to the cost of new generating resource alternatives. Specifically, Staff has suggested that it would be informative to compare the Company's expected demand-side management costs per megawatt hour saved to its expected supply side costs per megawatt hour. We agree and direct the Company to evaluate demand-side management alternatives using this methodology.	**Appendix 6P** Comparison of Per MWh Costs of Selected Resources
Case No. PUE-2013-00088 Final Order at 8	Further, we direct Dominion Virginia Power to include a broad band of prices used in future forecasting assumptions, such as forecasting assumptions related to fuel prices, effluent prices, market prices and renewable energy credit costs, in order to continue to set reasonable boundaries around the modeling assumptions, and to continue to refine the specific assumptions and sensitivity adjustments of its modeling data in future IRP filings.	**Section 2.6** Sensitvity Analyses **Section 4.4** Commodity Price Assumptions **Appendix 4N** ICF Commodity Price Forecasts

NOTICE TO THE PUBLIC
OF A FILING BY VIRGINIA ELECTRIC AND POWER COMPANY
OF ITS INTEGRATED RESOURCE PLAN
CASE NO. PUR-2023-00066

On May 1, 2023, Virginia Electric and Power Company (the "Company"), submitted to the State Corporation Commission ("Commission") its 2023 Integrated Resource Plan (the "2023 Plan" or "Plan") pursuant to § 56-597 *et seq*. of the Code of Virginia ("Va. Code"). An integrated resource plan, as defined by Va. Code § 56-597, is "a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility." Pursuant to Va. Code § 56-599 D, the Commission will analyze the Company's Plan and make a determination as to whether the Plan is reasonable and in the public interest.

On [**date**], the Commission entered an Order for Notice and Comment ("Procedural Order") that, among other things, directed the Company to provide notice to the public and offered interested persons an opportunity to comment or request a hearing on the Company's 2023 Plan.

An electronic copy of the Company's Plan may be obtained, at no charge, by requesting it in writing from Nicole M. Allaband, Esquire, McGuireWoods LLP, Gateway Plaza, 800 East Canal Street, Richmond, Virginia 23219, or nallaband@mcguirewoods.com. If acceptable to the requesting party, the Company may provide the documents by electronic means. Interested persons may also download unofficial copies of the 2023 Plan and other documents from the Commission's website: http://www.scc.virginia.gov/case.

On or before [**date**], interested persons may file written comments concerning the issues in this case with Bernard Logan, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. Interested persons desiring to submit comments electronically may do so by following the instructions found on the Commission's website: http://www.scc.virginia.gov/case. Comments shall refer to Case No. PUR-2023-00066.

On or before [**date**], interested persons may request that the Commission convene a hearing on the Company's 2023 Plan by filing a request for a hearing with the Clerk of the Commission at the address set forth above. Requests for hearing must include: (i) a precise statement of the filing party's interest in the proceeding; (ii) a statement of the specific action sought to the extent then known; (iii) a statement of the legal basis for such action; and (iv) a precise statement why a hearing should be conducted in this matter.

Any interested person may participate as a respondent in this proceeding by filing a notice of participation on or before [**date**]. Such notice of participation shall include the email addresses of such parties and their counsel. The respondent simultaneously shall serve a copy of the notice of participation on counsel to the Company. Pursuant to 5 VAC 5-20-80, *Participation as a respondent*, of the Commission's Rules of Practice and Procedure ("Rules of Practice"), any notice of participation shall set forth: (i) a precise statement of the interest of the respondent; (ii) a statement of the specific action sought to the extent known; and (iii) the factual and legal basis for the action. Any organization, corporation, or government body participating as a respondent must be represented by counsel as required by Rule 5 VAC 5-20-30, *Counsel*, of the Rules of Practice. All filings shall refer to Case No. PUR-2023-00066. For additional information about participation as a respondent, any person or entity should obtain a copy of the Commission's Procedural Order.

The Commission's Rules of Practice may be viewed at http://www.virginia.gov/case. A printed copy of the Commission's Rules of Practice and an official copy of the Commission's Procedural Order in this proceeding may be obtained from the Clerk of the Commission at the address set forth above.

VIRGINIA ELECTRIC AND POWER COMPANY

Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2023-00066
Docket No. E-100, Sub 192

Filed: May 1, 2023

Table of Contents

List of Acronyms

Acronym	Meaning
2020 Plan	2020 Integrated Resource Plan
2023 Plan	2023 Integrated Resource Plan
AC	Alternating Current
ACE Rule	Affordable Clean Energy Rule
AMI	Advanced Metering Infrastructure
ARB	Accelerated Renewable Energy Buyers
BATW	Bottom Ash Transport Water
BDM	Bass Diffusion Model
BESS	Battery Energy Storage System
BRA	Base Residual Auction
BSER	Best System of Emissions Reduction
¢/kWh	Cents per kilowatt-hour
CAGR	Compound Annual Growth Rate
CC	Combined-Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture and Sequestration
CHP	Combined Heat and Power
CIP	Customer Information Platform
CIR	Capacity Injection Rights
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
COD	Commercial Operation Date
COL	Combined Operating License
Company	Virginia Electric and Power Company
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
CVOW	Coastal Virginia Offshore Wind
CWA	Clean Water Act
DAC	Direct Air Capture
DC	Direct Current
DER	Distributed Energy Resource
DNV GL	DNV GL Energy Insights U.S.A.
Dominion Energy	Dominion Energy, Inc.
DOM LSE	Dominion Energy Load Serving Entity
DOM Zone	Dominion Energy Zone
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	U.S. Energy Information Administration

Acronym	Meaning
EFORd	Equivalent Forced Outage Rate Demand
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitations Guidelines
EM&V	Evaluation, Measurement and Verification
EO9	Virginia Executive Order 49
EPA	U.S. Environmental Protection Agency
ESCR	Effective Short Circuit Ratio
EV	Electric Vehicle
FACTS	Flexible Alternative Current Transmission Systems
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
FIP	Federal Implementation Plan
FRR	Fixed Resource Requirement
GHG	Greenhouse Gas
GTSA	Grid Transformation and Security Act of 2018
GW	Gigawatts
GWh	Gigawatt Hours
HVDC	High-voltage Direct Current
ICF	ICF Resources, LLC
IDP	Integrated Distribution Planning
IIJA	Infrastructure Investment and Jobs Act of 2021
IRA	Inflation Reduction Act of 2022
IRS	Internal Revenue Service
ISA	Interconnection Service Agreement
ITC	Investment Tax Credit
kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt Hours
LCOE	Levelized Cost of Energy
LNG	Liquified Natural Gas
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MGD	Million Gallons per Day
Moody’s	Moody’s Analytics
MW	Megawatts
MWh	Megawatt Hours
NAAQS	National Ambient Air Quality Standards
NCGS	North Carolina General Statute
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
NOVEC	Northern Virginia Electric Cooperative
NO_x	Nitrogen Oxide

Acronym	Meaning
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	The National Renewable Energy Laboratory
NSPS	New Source Performance Standards
NWA	Non-wires Alternatives
O&M	Operations and Maintenance
ODEC	Old Dominion Electric Cooperative
PJM	PJM Interconnection, L.L.C.
Plan	Integrated Resource Plan
Planning Period	15-year Period of 2024 to 2038
PLEXOS	PLEXOS Model
PPA	Power Purchase Agreement
Ppb	Parts Per Billion
PTC	Production Tax Credit
REC	Renewable Energy Certificate(s)
REPS	N.C. Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable Natural Gas
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCC	Virginia State Corporation Commission
SG	Standby Generation
SMR	Small Modular Reactor
SO_2	Sulfur Dioxide
Study Period	25-year Period of 2024 to 2048
SUP	Strategic Underground Program
ug/m^3	Microgram per cubic meter
V2G	Vehicle-to-grid
Va. Code	Code of Virginia
VCEA	Virginia Clean Economy Act
VCHEC	Virginia City Hybrid Energy Center
VEJA	Virginia Environmental Justice Act
WHP	Waste Heat to Power
WSP	Weatherization Service Providers

Introduction

Headquartered in Richmond, Virginia, Virginia Electric and Power Company (the "Company") currently serves approximately 2.7 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company is a subsidiary of Dominion Energy, Inc. ("Dominion Energy")—one of the nation's largest producers and transporters of energy, energizing the homes and businesses of more than seven million customers in 16 states with electricity or natural gas.

The Company's supply-side portfolio consists of 21,713 megawatts ("MW") of generation capacity, including approximately 1,164 MW of resources owned by third parties from which the Company purchases the output through power purchase agreements ("PPAs"). The Company's demand-side management ("DSM") portfolio consists of energy efficiency and demand response programs in Virginia and North Carolina. The Company owns approximately 6,800 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV in Virginia, North Carolina, and West Virginia; and approximately 60,000 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia and North Carolina. The Company is a member of PJM Interconnection, LLC ("PJM"), the regional transmission organization ("RTO") coordinating the wholesale electric grid in the Mid-Atlantic region of the United States. The Company's service territory is located within the Dominion Energy Zone ("DOM Zone") in PJM. The 2023 Integrated Resource Plan (the "2023 Plan" or the "Plan") was prepared for the Dominion Energy Load Serving Entity ("DOM LSE") within PJM.

The Company files this 2023 Plan with the Virginia State Corporation Commission ("SCC") in accordance with § 56-597 *et seq.* of the Code of Virginia (or "Va. Code") and the SCC's guidelines issued on December 23, 2008, in Case No. PUE-2008-00099. The Company also files this 2023 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 2023 Plan also addresses requirements identified by the SCC and the NCUC in prior relevant orders, as well as current and pending provisions of state and federal law.

The 2023 Plan covers the 15-year period beginning in 2024 and continuing through 2038 (the "Planning Period"), using 2023 as the base year. In certain instances described herein, the Company evaluates the longer 25-year period of 2024 to 2048 (the "Study Period"). Overall, the 2023 Plan is meant for use as a long-term planning document based on a "snapshot in time" of current technologies, market information, and projections, and should be viewed in that context.

Executive Summary

The priorities of the Company have not changed—to provide reliable, affordable, and increasingly clean power to its customers. However, this year the long-term projected amount of power needed in the DOM Zone materially increased. The 2023 PJM Load Forecast included a significant increase in the expected peak and energy demand in the DOM Zone over the Planning Period, with annual peak and energy load growth of nearly 5% and 7% respectively, over the next decade. This increase is driven primarily by data centers and, to a lesser extent, electrification in both the Company's service territory and in other service areas within DOM Zone. Winter Storm Elliott on December 23 and 24, 2022, also magnified the need for dispatchable generation, backup fuel sources, and resources that are available to generate during winter peaks. Through the development of this 2023 Plan, the Company addresses these needs with a diverse portfolio of resources.

The Company is transforming its distribution grid to provide an enhanced platform for distributed energy resources ("DERs") and targeted DSM programs; more secure and reliable service, leading to the increased availability of DERs; and more ways for customers to save energy and money through DSM programs and other rate offerings. The Company has also received approval of new customer offerings in Virginia to support and incentivize the installation of charging infrastructure for electric vehicles ("EVs"), including an offering to support fleet electrification.

Over the long term, achieving the clean energy goals of Virginia, North Carolina, and the Company will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy. This includes support for the testing and deployment of technologies, such as long duration energy storage; renewable natural gas; vehicle-to-grid; hydrogen; advanced nuclear; and carbon capture and sequestration, all of which have the potential to significantly reduce greenhouse gas emissions.

In this 2023 Plan, the Company presents five alternative plans (the "Alternative Plans") to meet customers' needs in the future under different scenarios, which are designed using constraint-based least-cost planning techniques and proven technologies:

- Plan A: This Alternative Plan presents a least-cost plan that meets only applicable carbon regulations and the mandatory renewable energy portfolio standard program ("RPS Program") requirements of the Virginia Clean Economy Act ("VCEA"). The Company presents this Alternative Plan in compliance with prior SCC and NCUC orders and for cost comparison purposes only. It is important to emphasize that Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.

- Plan B: This Alternative Plan includes the significant development of solar, wind, and energy storage envisioned by the VCEA, petitioned by 2035 and built by 2038. Plan B includes the development of six new small modular reactors ("SMRs") starting in 2034 and a second offshore wind project, providing carbon free power. This plan does require an increase in the Company's ability to import capacity and energy by 2040. Plan B also preserves existing generation and includes several new gas combustion turbines to address future energy and system reliability needs.

- Plan C: This Alternative Plan is like Plan B in preserving existing generation to address future system reliability, stability, and energy independence issues, with identical assumptions regarding the retirement of existing Company-owned carbon-emitting generation. Plan C differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.

- Plan D: This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045, resulting in zero carbon dioxide (“CO_2”) emissions from the Company’s fleet in 2046. In order to retire all carbon-emitting units by the end of 2045, the Company will need to build and buy significant incremental capacity to reliably meet customer load. Plan D shows the Company building over 4,500 MW of incremental energy storage and more than 3,000 MW of incremental SMRs to meet this need when compared to Plan B. Even with these additional resources, Plan D results in the Company purchasing 10,800 MW of capacity in 2045 and beyond, raising significant concerns about system reliability and energy independence, including over-reliance on out-of-state capacity to meet customer needs. This Plan will also require a substantial increase in energy purchase limits. Over time as more renewable energy and energy storage resources are added to the system and as other technology advances, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan D approach to maintain system reliability.

- Plan E: This Alternative Plan is like Plan D in retiring all Company-owned carbon-emitting generation by the end of 2045. Plan E differs from Plan D in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Like Plan D, Plan E would require the Company to build and buy significant incremental capacity and energy to reliably meet customer load. Over time as more renewable energy and energy storage resources are added to the system, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan E approach to maintain system reliability.

All Alternative Plans utilize the load forecast prepared by PJM; assume a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company’s existing solar facilities in Virginia; and assume that Virginia exits the Regional Greenhouse Gas Initiative (“RGGI”) before January 1, 2024. All plans assume the retirement of Yorktown 3, Chesterfield 5, and Chesterfield 6 in May 2023. The 2023 Plan also presents multiple sensitivities on various assumptions. Notably, the Company presents a high load sensitivity that would require increased capacity and energy purchases even earlier in the Plan. Increased market reliance shown in sensitivities with higher load or less energy efficiency is a reliability concern. The Company also presents sensitivities on all Alternative Plans that show the higher cost to customers if Virginia remains in RGGI.

The following table presents a high-level summary of the Alternative Plans. The resource additions shown here are incremental to existing generation and approved generation under construction, including nearly 2,600 MW of offshore wind.

Executive Summary Table: 2023 Plan Results

	Plan A	Plan B	Plan C	Plan D	Plan E
NPV Total ($B)	$109.70	$127.70	$127.20	$140.90	$138.00
Approximate CO_2 Emissions from Company in 2048 (Metric Tons)	43.8 M	35.9 M	36 M	0 M	0 M
Solar (MW)	10,800 15-yr 19,800 25-yr	10,875 15-yr 19,875 25-yr	10,800 15-yr 19,800 25-yr	10,875 15-yr 23,955 25-yr	11,094 15-yr 24,294 25-yr
Wind (MW)	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr
Storage (MW)	1,050 15-yr 3,960 25-yr	2,370 15-yr 5,190 25-yr	2,220 15-yr 5,220 25-yr	2,370 15-yr 9,780 25-yr	2,910 15-yr 10,350 25-yr
Nuclear (MW)	-- 15-yr -- 25-yr	804 15-yr 1,608 25-yr	804 15-yr 1,608 25-yr	1,608 15-yr 4,824 25-yr	1,072 15-yr 4,288 25-yr
Natural Gas Fired (MW)	5,905 15-yr 9,300 25-yr	2,910 15-yr 2,910 25-yr	2,910 15-yr 2,910 25-yr	970 15-yr 970 25-yr	970 15-yr 970 25-yr
Retirements (MW)	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr 11,399 25-yr	-- 15-yr 11,399 25-yr

As can be seen in the Summary Table, all Alternative Plans show significant solar, wind and energy storage development over the 25-year Study Period. Additionally, Plans B through E include development of SMRs. Due to an increasing load forecast, and the need for dispatchable generation, the Alternative Plans show additional natural gas-fired resources and preserve existing carbon-emitting units beyond statutory retirement deadlines established in the VCEA. The law explicitly authorizes the Company to petition the SCC for relief from these requirements on the basis that the unit retirements would threaten the reliability or security of electric service to customers. If the Company ultimately retires all carbon-emitting generation by the end of 2045, as shown in Plans D and E, significant incremental wind, solar, nuclear, and energy storage resources are needed. While all Alternative Plans incorporate only known technologies, the Company fully expects that new technologies could take the place of today's technologies over the 15-year Planning Period and the 25-year Study Period.

Going forward, long-term integrated resource plans will evolve and will continue to support the cleaner future envisioned by public policy, by lawmakers, and by the Company. As noted, this future, while achievable, will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy. It will also require further study and analyses of necessary investments in the transmission and distribution systems to ensure the reliable electric service that customers expect and deserve. For example, the Company knows that greater investments in some plans are required to support greater capacity and energy imports. Overall, the Company's deliberate transitional approach to a cleaner future has, and will continue, to provide customers a path to clean energy that meets public policy objectives while maintaining the standard of reliability necessary to power Virginia's and North Carolina's modern economies.

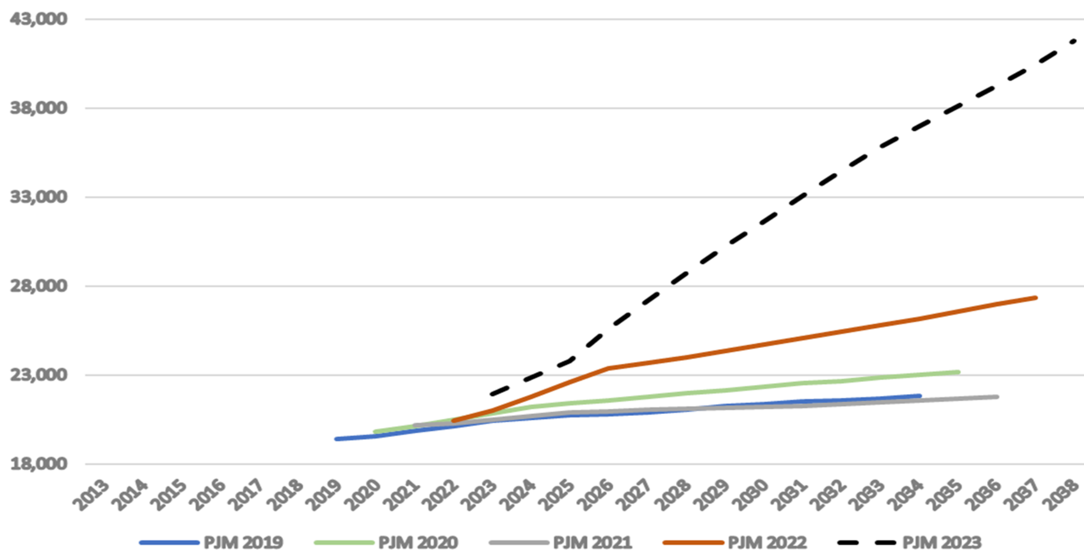
<u>**Chapter 1: Significant Developments and Context for the Integrated Planning Process**</u>

The Company's comprehensive planning process considers emerging policy, market, regulatory, and technical developments that could affect its operations and, in turn, its customers. The Company provides the following discussion of significant developments requiring a major revision to previous modeling, consistent with the requirements of the SCC and the NCUC.

1.1 PJM Load Forecast and Energy Transition Risks

PJM's 2023 load forecast for the DOM Zone increased significantly relative to the prior year's forecast, as can be seen in Figure 1.1.1. In this forecast, PJM made several changes to its load forecasting methodology, most of which followed an independent consultant's review of PJM's modeling process. These changes included replacing annual/quarterly end-use indices with monthly/daily indices, replacing daily models with hourly models, and incorporating a data center forecast covering fifteen years, instead of just five years, from load serving entities like the Company with significant data center growth. Rising energy and peak growth from data centers in Virginia is a key driver of PJM's DOM Zone forecast in overall energy and peak demand.

Figure 1.1.1: PJM Summer Peak Forecast for DOM Zone (MW)



Even with the above changes, a few challenges remain with using PJM's load forecast for the Company's long-term resource planning process related to region-specific considerations (*e.g.*, class-level sales modeling, electrification, energy efficiency, net metering, etc.), forecast timing, and forecast translation from the DOM Zone to the DOM LSE. These challenges are not a criticism of the PJM forecast but are associated with the SCC-required use of that forecast for the Company's long-term planning. Accordingly, while the Company has utilized the 2023 PJM Load Forecast in the development of all Alternative Plans, as required, the Company also shows a sensitivity of Alternative Plan B using the 2023 Company Load Forecast.

In February 2023, PJM issued an "Energy Transition in PJM: Resource Retirements, Replacements, & Risks" report highlighting the trends that are increasing reliability risks. Specifically, PJM identified:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region due to the timing of resource availability, load growth, and new generation.
- Thermal generators are retiring at a rapid pace throughout the PJM region due to government and private sector policies, as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, multiple megawatts of these resources are needed to replace one megawatt of thermal generation.

PJM forecasts DOM Zone load by isolating data center load, and requests the Company, as well as other load serving entities, provide a data center load forecast. The Company prepares this load forecast using statistical regression and confidential and proprietary customer information. A detailed description of the Company's forecasting method can be found in Section 4.1.5, ***Data Center Forecast***. In prior years, PJM has requested a five-year data center projection and used a long-term historical average growth rate to project data center growth beyond five years, but in preparation of its 2023 load forecast, PJM requested a fifteen-year data center forecast. The resulting growth seen in the PJM DOM Zone forecast this year is largely driven by this change.

1.2 Significant Federal Legislation

1.2.1 Inflation Reduction Act

In August 2022, the Inflation Reduction Act of 2022 ("IRA") became law. The IRA includes various climate and energy provisions expected to have a positive effect on current and future Company clean energy investments. The IRA generally extends and adds incentives to promote clean energy nationwide, including approximately $369 billion for climate and clean energy provisions, such as increased federal tax credits for solar, wind, storage, and nuclear.

There are generally two types of federal tax credits available to incentivize investment in renewable energy generation facilities—investment tax credits ("ITCs") or production tax credits ("PTCs"). ITCs are based on the amount of eligible capital invested in a facility. The ITC is a one-time credit that is calculated by multiplying the credit percentage times the amount of qualified capital (*i.e.*, the cost of constructing or acquiring property that is eligible for the credit, such as solar or wind energy property). PTCs are based on the amount of renewable electricity produced and sold by a facility. The PTC is calculated annually for a ten-year period by multiplying the credit amount, adjusted annually for inflation, by the kilowatt-hours ("kWh") of electricity produced and sold by the facility during the year.

The IRA includes several provisions relevant to the Company. The IRA extends ITCs and PTCs for renewable energy technologies, including wind and solar, for at least ten years and expands the qualifying technologies to include hydrogen, biogas, and, after 2024, other zero-emissions facilities, including new nuclear. The IRA also expands the qualifying technologies for ITCs specifically to include stand-alone storage greater than five kilowatts ("kW"). Any incremental credit that the Company receives as a result of the IRA will be passed on to customers through lower project costs. Eligible property for credits is expanded to include interconnection property for certain small projects (*i.e.*, five MWs or less). Section 4.6, ***Federal Tax Credit Assumptions***, provides details on how the Company incorporated the Inflation Reduction Act into its modeling for the 2023 Plan.

1.2.2 Infrastructure Investment and Jobs Act

The Infrastructure Investment and Jobs Act of 2021 ("IIJA") was enacted in November 2021 to comprehensively invest in the nation's infrastructure. Relevant to utilities, the IIJA aims to build a national network of EV chargers; upgrade power infrastructure to deliver clean, reliable energy across the country and deploy cutting-edge energy technology to achieve a zero-emissions future; and make infrastructure resilient against the impacts of climate change, cyber-attacks, and extreme weather events. The IIJA provides several competitive funding opportunities, some of which will be directly available to utilities, and some of which will be partnership-based, meaning, for example, partnerships between the Company and school districts in its territory for electrification of school buses.

Generally, the Company intends to actively participate in IIJA opportunities that align with its operations in Virginia and North Carolina while providing overall net benefits to its customers. The Company has submitted applications and concept papers for IIJA direct funding opportunities, including expansion of rural broadband, grid modernization, and energy storage. The Company has also taken steps to support its partners indirectly through transportation electrification initiatives with the Virginia Department of Transportation, public transit agencies, and school districts. The Company is also a partner in the Mid-Atlantic Coalition, which is pursuing funding for the development and expansion of clean hydrogen infrastructure for the Mid-Atlantic Hydrogen Hub.

Importantly, the Company does not intend to limit its evaluation of IIJA funding opportunities to a one-time review of the programs. Instead, the Company intends to continually review available IIJA opportunities over the law's five-year funding window. The Company is also ensuring that the SCC and NCUC stay informed of the Company's progress in taking advantage of IIJA opportunities, including by participating in relevant dockets (SCC Case No. PUR-2022-00180 and NCUC Docket No. M-100, Sub 164).

1.3 Severe Weather Events

Since 2020, severe weather events across the country have highlighted the vulnerability of the electric grid to natural threats, from a generation, transmission, and distribution perspective.

In December 2022, the effects of Winter Storm Elliott set a new demand peak for the DOM Zone and emphasized certain system planning considerations for the future. The weather on December 23, 2022, was unprecedented for that time of year in Virginia and North Carolina, with a severe temperature drop and resulting spike in load during a holiday weekend. A record-breaking plunge of 29 degrees over 12 hours surpassed the previous PJM record of a 22-degree drop during the 2014 Polar Vortex. As cold weather gripped the PJM region and power demand spiked, generators across the PJM system experienced high levels of forced generation outages—an unanticipated failure of all or part of a specific generator to perform. Approximately 70% of the outages were natural gas resources, likely driven by lack of fuel supply, lack of fuel purchases, or gas pipeline pressure challenges. PJM implemented emergency procedures, including calls for synchronized reserves, a Maximum Generation Emergency Action, and a call on demand response resources to keep the system operating in a reliable manner. Generation outages expanded further, and by the morning peak of December 24, 2022, PJM was missing approximately 46,000 MW of its generation fleet.

The Company's generation fleet performed well during Winter Storm Elliott, but the Company's natural gas-fired generation fleet experienced some limitations related to upstream pipeline pressure issues and units returning from outage as it related to the natural gas supply market for the four-day holiday weekend. Namely, intra-day natural gas supplies were insufficient and scarce, beyond supplies traded and scheduled on the pipelines, in the day ahead market (Friday, December 23). Many of the Company's dual-fueled units burned backup fuel oil due to economics and limited gas supply.

Winter Storm Elliott highlighted the importance of gas generators receiving sufficient and timely electric price signals, such that enough fuel can be purchased and scheduled in advance of the generation need. A disproportionate reliance on intra-day gas supplies is not sustainable during peak generation demand periods and highlights the importance of supplies or services that augment flowing gas supply. Options to reduce this risk include pipeline storage, liquified natural gas ("LNG"), peaking supply options, and on-site alternative fuels. The Company is evaluating these options. Nuclear, oil, and coal units were essential to reliable operations. The event highlighted the need for dispatchable generation, especially during the winter, the need for backup fuel and sufficient ancillary commodities (*e.g.*, ammonia or demineralized water) on site, and the risk of relying too heavily on market purchases or PJM Day Ahead awards during extreme weather.

While the PJM system was able to maintain reliable operations throughout this event, operating reserves were very limited. Utilities in Tennessee and North Carolina experienced rolling blackouts. Both PJM and the Federal Energy Regulatory Commission ("FERC") are conducting investigations, and the Company will follow the results closely.

In addition to evaluating options to improve generation availability, through its Grid Transformation Plan, the Company will continue to strategically invest significantly into strengthening electric distribution infrastructure, improving communications and controls, and proactively maintaining the rights-of-way that comprise and provide access to Company facilities. These investments will create a more resilient grid, improve reliability, and offer faster recovery after severe weather events. In January 2022, Winter Storm Frida impacted large areas of central and northern Virginia. Frida created an opportunity for the Company to observe the benefits of recent mainfeeder hardening efforts on affected infrastructure in central Virginia. The Company observed fewer outages and less significant damage on impacted facilities that had been hardened compared to those that had not yet been hardened.

1.4 Small Modular Reactors

As a carbon-free complement to renewable energy generation, nuclear generation provides a reliable and clean source of energy. Nuclear power thus remains a fundamental component of the clean energy transition to net zero emissions and a necessary resource to maintain reliability and affordability. SMRs provide a promising future supply-side resource option.

SMRs are a classification of nuclear reactors designed to produce up to 300 MW of electricity per reactor. Their modular nature allows for portions of the plant to be factory-fabricated and delivered to the site, improving construction quality and reducing construction timelines. Design improvements to SMRs have reduced the safety risks associated with traditional nuclear technology, and when coupled with their small size and modular construction process, make it possible to locate SMRs on a wide variety of sites, including brownfield sites (*e.g.*, retired fossil-fuel generation sites), existing nuclear power generation sites, other industrial areas, and areas closer to the electric demand. Such sites could be helpful in utilizing existing transmission infrastructure and providing a just transition for the local workforce.

Among the key benefits and improvements of SMRs over traditional nuclear technology is the increased use of passive safety systems. Passive safety systems rely on natural forces, such as gravity, pressure differences, or natural heat convection to accomplish safety functions without the need for operator action or a power source. This results in a power plant that is simpler, has less equipment, and does not require an emergency source of power. The fabrication of SMRs includes the repeat production of modular assemblies, incorporating a variety of components to a consistent design, reducing cost and time for production, and thus making the SMRs scalable.

Another key advantage of SMRs is their capability to produce electricity around the clock, providing reliability and stability to the electric grid. The SMR designs being developed are also expected to be dispatchable, meaning that they will be able to ramp up and down to meet demand or complement the Company's generation resources within timeframes comparable to natural gas-fired combined-cycle facilities, thus providing another resource to ensure that the system remains reliable and resilient for the Company's customers into the future.

Although this technology has not yet been deployed at scale, SMR design activities and regulatory licensing are accelerating both domestically and abroad. The Nuclear Regulatory Commission ("NRC") has engaged in varying degrees of pre-application activities with several SMR reactor designers and license applicants. In 2022, the NRC voted to certify the first SMR design in the United States, with final certification issued in early 2023. Other designs are expected to be approved over the next several years. Additionally, there are numerous utilities domestically and internationally that have announced intentions to deploy SMRs, which will contribute to the acceleration of development activities.

The Company plans to continue evaluating the feasibility, operating parameters, and costs of SMRs and will update modeling assumptions related to SMRs in future filings. Potential cost reductions relative to the assumptions reflected in the 2023 Plan may be realized as the design of SMRs matures and as anticipated construction schedules are established. Based on updated capital, operating and maintenance costs, continued progress of licensing timelines, and new policy initiatives or legislative changes, it is conceivable that the deployment of SMRs could be further accelerated by the Company, with the first SMR being placed in service within a decade.

1.5 Federal Interconnection Queue Reform

In early 2021, PJM announced a pause in its generation queue study process due to the backlog of queue projects waiting on final interconnection service agreements ("ISA"). In conjunction with this queue pause, PJM started a stakeholder process—the Interconnection Process Reform Task Force—to develop a new interconnection queue analysis process that would accommodate the integration of large numbers of renewable energy projects within the transmission system. This new queue study process was approved by PJM's stakeholders in May 2022; PJM filed for regulatory approval with FERC in June 2022 and expects to start the new process in the third quarter of 2023. This new process will eliminate PJM's current serial study process under which a reliability study is completed for each specific interconnection request, typically representing one project, and then all costs related to any necessary network upgrades fall on the developer of that one project even though other projects on the same feeder may contribute toward the need for the network upgrade. Under the proposed new process, all projects located on the same feeder are placed in one cluster for the reliability study and cost allocation analysis. Cost allocation for any identified network upgrades will remain within the cluster under study. Once the transition to this new process is complete, the new study process is projected to take less than 24 months from start to finish, which includes the execution of final ISAs. Some projects currently in the queue are eligible to be "fast tracked," but the ISAs for other potential projects may be delayed.

Separate from PJM's initiatives related to its interconnection queue, FERC issued a notice of proposed rulemaking in June 2022 to address the significant backlogs in interconnection studies across the country affecting more than 1,400 gigawatt ("GW") of new generation as of 2021. The FERC notice is proposing to implement a first-ready served queue cluster study process, improved interconnection queue processing speed, updated modeling and performance requirements for system reliability, and technological advancements to the interconnection process. FERC is also proposing that the North American Electric Reliability Corporation ("NERC") develop a benchmarking planning case for extreme weather events and that transmission providers develop corrective action plans when performance requirements are not met. FERC is proposing this change to address several extreme weather events that initiated the load shedding process, resulting in loss of power to customers.

Queue reform at the federal level will help to reduce the number of speculative projects submitted to the interconnection queue and evaluate reliability and transmission network upgrade expenses over a portfolio of projects. However, it is possible that delays in construction timelines may impact the Company's existing unit retirement assumptions and new generation additions in future filings.

1.6 Commodity Price and Cost Assumptions

Over the past 24 months, the United States has experienced high volatility in fuel and energy prices, more extreme weather events, supply chain constraints, and federal interconnection queue reform. These current circumstances highlight the need for resource diversity and dispatchable generation, as well as caution against retiring existing resources until the Company is certain it can reliably meet demand with newer technologies.

Construction costs for new resources also reflect market changes over the same period affected by record levels of inflation and global supply chain disruptions that are placing upward pressure on material and commodity costs. The result is a material increase in overall build costs, particularly for solar, onshore wind, and storage resources.

For modeling purposes, all cost and planning assumptions were included in the modeling as of March 15, 2023.

1.7 Virginia REC Market

The VCEA instituted a mandatory RPS Program in Virginia under which the Company must meet annual requirements for the sale of renewable energy based on a percentage of non-nuclear electric energy sold to retail customers in the Company's service territory, starting at 14% for the 2021 compliance year and increasing to 100% in compliance year 2045 and beyond. In years 2021 to 2024, the Company may use renewable energy certificates ("RECs") for RPS Program compliance originating from renewable energy facilities located within the PJM region. Beginning in 2025, 75% of the RECs used by the Company for RPS Program compliance must come from resources located in Virginia, with additional limitations on the type of facilities that qualify for compliance. Additionally, of the required percentage in each compliance year, 1% of the RECs must be from certain DERs located in Virginia with a nameplate capacity of 1 MW or less.

REC prices within existing PJM REC markets have risen since the enactment of the VCEA, in part because of the increased demand for RECs to comply with the mandatory RPS Program. The mandatory RPS Program will also result in the establishment of a new Virginia REC market because of the requirement for the Company to retire a significant number of RECs from Virginia-sited renewable energy facilities beginning in 2025. Although a market for Virginia in-state RECs has not fully developed, the 2023 Plan includes a Virginia REC price forecast. Based on current market dynamics, the price for RECs in the Virginia REC market will likely be equal to or higher than the PJM REC market price.

From a long-term planning perspective, the Company has concerns that RECs eligible for RPS Program compliance will not be widely available for the Company's use unless new renewable energy resources are built, especially in Virginia. The majority of Virginia RPS eligible sources are registered for renewable portfolio standard compliance in multiple states. As a result, it is difficult to ascertain how many of these RECs will be needed by other entities for compliance in other jurisdictions. There is also a large and growing number of corporate buyers in the market who procure and retire RECs to meet their corporate sustainability goals; these RECs will not be part of available supply for the Company to meet the Virginia RPS Program requirements. The ability of other entities to bank eligible RECs in other jurisdictions further complicates an analysis of available REC supply in the market.

According to the Company's current estimates, the Company's need for RECs from eligible resources will grow from approximately 9 million in 2025 to approximately 47 million in 2035. In the absence of the two incumbent electric utilities in Virginia developing these resources—either through construction or acquisition by the utility or through incentivizing the construction by third-party developers through PPAs—it is unlikely that the necessary renewable energy development in Virginia would materialize to meet the RPS Program requirements. The development targets set forth in the VCEA seem to recognize as much by requiring the Company and Appalachian Power Company to petition the SCC for the necessary approvals to construct, purchase, or acquire a significant amount of solar and wind resources. Because the Virginia REC market is in its infancy, it is difficult to predict what the future REC supply will be. However, if the market does not develop and the REC market is undersupplied, the market price of RECs is likely to become the equivalent of the VCEA-imposed deficiency payment for supply and demand to be in equilibrium. The Company will continue to closely monitor the feasibility of future RPS compliance.

This year the Company adjusted the REC forecast to account for a growing volume of accelerated renewable energy buyer ("ARB") customers who meet their REC needs with contracts within PJM. Section 9.3, ***Accelerated Renewable Energy Buyers*** provides more details about these customers. Even with this adjustment, due to the significant load growth in the 2023 PJM Forecast, the Company is significantly short of the required RECs for RPS compliance in alternative plans A, B, and C as early as 2036. By the end of the Study Period, customers will be paying as much as $2 billion a year in deficiency payments, at a rate of more than $59 per megawatt hour ("MWh").

See Section 4.7.4, ***REC-Related Assumptions***, for details on the assumptions the Company made for modeling purposes for this 2023 Plan based on these concerns.

1.8 Distribution Grid Transformation

Electricity has become a basic need, vital to the country's economy, public safety, and way of life. Critical services and infrastructure increasingly rely on electricity, including homeland security, medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pump facilities. The transportation industry is actively continuing its shift toward electrification of personal vehicles, fleets, and mass transit. Another vital resource powered by electricity is the internet, which drives commerce and everyday life. As society has grown more dependent on electricity, customers expect highly reliable service. The critical need for reliable electric service became even more acute in 2020, when life for many Americans—including commerce, education, and health—shifted to the home, and the internet, because of the pandemic. While service interruptions have always been an inconvenience, the safe, reliable, and consistent grid connectivity has never been more important than it is today.

In addition to the importance of reliable electric service, fundamental changes in the energy industry driven by the rise in DERs have prompted the need for utilities across the country to modernize their distribution grids. In response to this need, the Company prepared a comprehensive plan to transform its distribution grid in Virginia (the "Grid Transformation Plan") to meet the changing landscape of the energy industry while continuing to provide the reliable service that its customers expect and deserve. The Grid Transformation Plan was first presented to the SCC in 2018, and from the initial investments in grid transformation projects the Company has seen notable successes that have had a direct and positive effect on its customers.

The passage of time has validated the need for the Grid Transformation Plan. The Company has seen the shift toward DERs, with an 86% increase in executed interconnection agreements for solar interconnections through the Company's Virginia queue between year-end 2021 and year-end 2022, a 59% increase in net energy metering customers, and an approximately 50% increase in customers with EVs in the Company's Virginia service territory. In addition, major weather events and physical attacks on utility infrastructure continue to show that more work is needed to achieve the objectives of grid transformation.

See Section 8.3, ***Grid Transformation Plan***, for a description of the successes of the Grid Transformation Plan to date and an overview of the next phase on investments currently pending before the SCC.

1.9 New and Developing Technologies

Dominion Energy's Innovation and Sustainable Technologies business unit continues to help guide the Company toward the clean future envisioned by Virginia and North Carolina. Some of the more promising new technologies being investigated are as follows:

- **Power Generation Technology with Carbon Capture and Sequestration**. Natural gas combined-cycle plants fitted with carbon capture and sequestration ("CCS") are being consistently modeled as a necessary component of a low-carbon electric generation portfolio. Models of low-carbon scenarios by the Intergovernmental Panel on Climate Change, the International Energy Agency, Bloomberg New Energy Finance, and others all show significant contributions from CCS in the electric generation sector. CCS would allow a significant amount of existing dispatchable generation to stay online, while significantly reducing the carbon emitted by these plants. Research is ongoing into the storage and commercial uses for captured carbon. This technology is not currently allowed under the VCEA, which requires the Company's carbon-emitting generators in Virginia to retire by 2045, barring a petition for relief due to reliability or security concerns.

- **Hydrogen.** Hydrogen is both a fuel and a carrier that can be used to store and transport energy. Opportunities exist in the production, transportation, and usage of hydrogen to support a clean energy future when produced from low- or no-carbon sources. Examples include the use of hydrogen to "co-fire" natural gas generation providing peaking support. Hydrogen produced using excess renewable energy that may result as increasing amounts of renewable generation resources are added to the grid and provides medium and long-term energy storage opportunities for later use in natural gas power plants.

- **Electric Vehicles as a Resource.** Electric vehicles are becoming more prolific in most forms of transportation. With EVs, new technologies and software are being developed to maximize the benefits of electrification, such as load shifting and other applications that complement renewable generation. For example, vehicle-to-grid ("V2G") technologies are being developed through which electricity stored in EV batteries can be fed back onto the grid to lower peak demand or to provide grid support. See Section 8.6, ***Electric School Bus Program***, for a discussion of the Company's Electric School Bus Program through which it seeks to explore V2G technology. A precursor to taking advantage of this resource is a modernized grid that has full situational awareness.

- **Renewable Natural Gas.** Renewable natural gas ("RNG") is derived from biomethane or other renewable resources and is pipeline-quality gas that is fully interchangeable with conventional natural gas. RNG can thus be safely employed in any end use typically fueled by natural gas, including electricity production, heating and cooling, industrial applications, and transportation. Adding RNG as a source of natural gas generation reduces overall emissions and, in some cases, serves as a carbon offset. These sources may be expanded based on new technologies to capture RNG from untapped sources and in remote areas.

- **Continuous Improvement in Solar Output.** Solar technology improvements such as advanced trackers, bifacial modules, and other technologies continue to improve capacity, output, intermittency profiles, and operational efficiency of solar generation. As these technologies mature, these improvements—especially higher capacity factor improvements—could provide more carbon-free generation with potentially less land use.

- **Medium and Long Duration Energy Storage.** The need for energy storage will grow with the proliferation of intermittent generation. Storage technologies that are on the horizon include new and improved batteries, hydrogen, thermal storage, and mechanical storage. Of particular interest are recent strides in the non-lithium alternatives and long duration batteries, where several technologies have announced pilot projects with utilities across the nation. Progress in the piloting phase will support greater levels of commercialization. Medium and long duration storage can provide significant benefits to the grid during extended periods of high load or when other fuels may be in short supply. See Section 5.5.1, ***Supply-Side Resource Options***, for additional discussion of energy storage technologies.

- **Carbon Offsets.** There is a substantial and growing market in carbon offsets in the United States. Carbon offsets can be generated by any activity that compensates for the emission of CO_2 or other greenhouse gases ("GHGs"). These offsets are measured in carbon dioxide equivalents ("CO_2e") by providing for an emission reduction elsewhere. Because GHGs are widespread in Earth's atmosphere, there is a climate benefit from emission reductions regardless of where the reductions occur. If carbon reductions are equivalent to the total carbon footprint of an activity, then the activity is said to be "carbon neutral." Carbon offsets can be bought, sold, or traded as part of a carbon market. Carbon offsets, verified by third parties, are used in voluntary and compliance markets across the country. The Company is focused on decarbonizing as much as possible first without the use of offsets.

- **Direct Air Capture Technology.** This aspirational technology is an industrial process for large-scale capture of atmospheric CO_2. Direct air capture ("DAC") technology pulls in atmospheric air then, through a series of chemical reactions, extracts the CO_2 from it while returning the rest of the air to the environment. This is what plants and trees do every day as they photosynthesize, except DAC technology does it much faster, with a smaller land footprint, and delivers the CO_2 in a pure, compressed form that can then be stored underground or reused. The potential of the DAC technology is tied to systems where excess or curtailed renewable energy is available at a very low cost to power the industrial process that removes CO_2 from the air. Utilizing the captured CO_2 to develop other products provides additional support to this process. Captured CO_2 can be produced in a solid form for safe storage creating a "negative emissions" industrial scale process or can be paired with end-use applications such as CO_2 enhanced oil field recovery or development of synthetic fuels to provide carbon neutral transportation fuels.

- **Methane Pyrolysis.** Methane pyrolysis converts natural gas into hydrogen and carbon solid (such as high-quality graphite) using iron ore and other types of catalyst. The aim of the methane pyrolysis is to achieve savings by using existing natural gas infrastructure, as well as providing "clean" hydrogen with significantly lower CO_2 emissions. This "clean" hydrogen can then be used in a range of developing clean energy applications, including power generation. The graphite can be used in the production of lithium-ion batteries.

- **Fusion.** Fusion offers a potential long-term energy source based on a controlled thermonuclear fusion reaction by combining two nuclei to form a new nucleus, while releasing energy. Fusion reactors have been researched for decades, and history was made at the U.S. National Ignition Facility in 2022 when an inertial confinement laser-driven fusion machine produced a positive fusion energy gain factor—that is, more power output than input. There is an abundant fuel source for fusion energy, which produces no GHGs and does not generate used nuclear fuel. There are currently multiple companies working towards commercialization of various types of fusion energy technologies.

- **Advanced Analytics.** The economy is experiencing both a rapid increase in computing power and an explosive growth in data. Both trends will allow energy companies to manage the electric grid and aggregate resources in ways that they have not been able to do in the past, providing additional opportunities to reduce CO_2 emissions. A precursor to the use of this data is a modernized grid that gathers and aggregates data through advanced metering infrastructure ("AMI") and intelligent grid devices and incorporates a sophisticated distributed energy resource management system, for planning and operation of the electric grid from a systems perspective.

1.10 Other Legislative Developments

During its 2023 Regular Session, the Virginia General Assembly passed several pieces of legislation which bear mentioning from an integrated resource planning standpoint. For modeling purposes, the Company assumed all proposed legislation would be approved.

- **House Bill 1643 and Senate Bill 1121.** These bills establish that it is the policy of the Commonwealth to "encourage the capture and beneficial use of coal mine methane, defined as methane gas captured and produced from an underground gob area associated with a mined-out coal seam that would otherwise escape into the atmosphere." The Company is mindful of the report due by November 15, 2023, from the Virginia Department of Energy on avenues to accomplish this policy objective and reiterates its commitment to evaluate emerging supply-side energy resource alternatives. On March 24, 2023, Virginia Governor Youngkin signed both bills into law, with an effective date of July 1, 2023.

- **House Bill 1770 and Senate Bill 1265.** Among other things, these bills amend and reenact statutes governing the manner in which the SCC conducts reviews of the Company's rates for generation and distribution services. These provisions have no impact on the modeling which informs the Alternative Plans presented herein. However, relevant ratemaking provisions—including a requirement to combine a subset of rate adjustment clauses with the Company's costs, revenues, and investments for generation and distribution services and the potential securitization of certain deferred fuel costs—are reflected in the Virginia

Consolidated Bill Analysis. The bills also direct the SCC to utilize information from the Company's integrated resource plans or RPS Development Plans in discussing, within an existing annual report, "the reliability impacts of generation unit additions and retirement determinations," as well as the potential impact of such unit additions and retirements determinations on "the purchase of power from generation assets outside the Virginia jurisdiction to serve the [Company's] native load." On April 12, 2023, the Virginia General Assembly adopted a series of largely technical amendments to both bills proposed by Virginia Governor Youngkin; the bills thus became law as amended, with an effective date of July 1, 2023.

- **House Bill 2026 and Senate Bill 1231.** These bills eliminate a statutory requirement for the Company—barring a petition for relief on the basis that such requirement would threaten the reliability or security of electric service—to retire all biomass-fired electric generating units that do not co-fire with coal by December 31, 2028. Therefore, the timing of potential retirements for the Company's biomass generators would be determined as a part of the retirement analysis. The bills also provide that the environmental attributes associated with biomass units may be used to comply with RPS program requirements, subject to certain conditions. As a result of this bill, in all Alternative Plans, the biomass stations Altavista, Southampton, and Hopewell are assumed to remain online for the duration of the plans and all RECs generated during the Study Period are used for RPS compliance. Virginia Governor Youngkin has a 30-day window ending May 12, 2023, to either sign or veto the bills. If the Governor does not act on the bills within this timeframe, they will become law without his signature with an effective date of July 1, 2023.

- **House Bill 2275 and Senate Bill 1166.** These bills shift the filing deadline for future integrated resource plans to October 15 of the year preceding the SCC's biennial reviews of the Company's rates for generation and distribution services (*i.e.*, in 2024, 2026, and so on). The bills further require the Company to submit annual updates to its integrated resource plans by October 15 of the years in which it is subject to such biennial reviews (*i.e.*, in 2025, 2027, and so on). It is important to note that North Carolina still requires that full Plans and update filings be submitted to the NCUC by September 1 each year. In addition, the legislation directs the Company to "conduct outreach to engage the public in a stakeholder review process and provide opportunities for the public to contribute information, input, and ideas" when preparing future integrated resource plan filings. The Company will report on public outreach efforts to the SCC at the time of future filings, as directed by the legislation. On April 12, 2023, the Virginia General Assembly adopted amendments to both bills proposed by Virginia Governor Youngkin; the bills thus became law as amended, with an effective date of July 1, 2023.

- **House Bill 2305.** This bill requires the Company to demonstrate, as part of a petition for a certificate of public convenience and necessity ("CPCN"), that certain proposed solar facilities were subject to competitive procurement or solicitation. On March 27, 2023, Virginia Governor Youngkin signed the bill into law, with an effective date of July 1, 2023.

- **House Bill 2444 and Senate Bill 1441.** These bills amend and reenact statutory language establishing that "the construction or purchase by a public utility of one or more offshore wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth, with an aggregate capacity of up to 5,200 megawatts" is in the public interest. Specifically, the legislation accelerates the time horizon of this public interest declaration from December 31, 2034 to December 31, 2032. In Alternative Plans B and D, the Company build plan reflects the second offshore wind project fully operational by January 1, 2033. Virginia Governor Youngkin has a 30-day window ending May 12, 2023, to either sign or veto the bills. If the Governor does not act on the bills within this timeframe, they will become law without his signature with an effective date of July 1, 2023.

- **HB 2482 and SB 1541.** These bills direct the SCC to issue its final order for CPCN regarding projects identified by PJM as part of Baseline Project b3718 no later than 270 days after the filing date. For such projects filed prior to January 1, 2023, the bills direct the SCC to issue its final order within 90 days of the bills' effective date. Such approvals would not substantially change the outlook for the Company's need to import capacity and energy—all Alternative Plans presented herein contemplate a significant expansion of import capability. The Company therefore welcomes any developments which expedite deployment of new electric transmission infrastructure. On March 24, 2023, Virginia Governor Youngkin signed both bills into law, with an effective date of July 1, 2023.

- **Senate Bill 1477.** This bill authorizes the Company to establish an offshore wind affiliate for the purpose of securing a noncontrolling equity financing partner for the commercial-scale Coastal Virginia Offshore Wind ("CVOW") project, subject to SCC approval. The Company would retain responsibility to construct and operate the project irrespective of such approval—therefore, the legislation does not affect how the Company models the project's expected capacity or energy output. On March 24, 2023, Virginia Governor Youngkin signed the bill into law, with an effective date of July 1, 2023.

- **Senate Bill 1323.** This bill requires the SCC to establish annual energy efficiency savings targets for the Company's customers who are low-income, elderly, disabled, or military veterans. In establishing such targets, the SCC must seek to optimize energy efficiency and the health and safety benefits of utility energy efficiency programs. The bill requires the Company to make best efforts to coordinate such energy efficiency programs with any health and safety upgrades provided through energy efficiency programs authorized by provisions of the Code of Virginia, when reasonably feasible to do so and at the Company's sole discretion. On March 27, 2023, Virginia Governor Youngkin signed the bill into law, with an effective date of July 1, 2023.

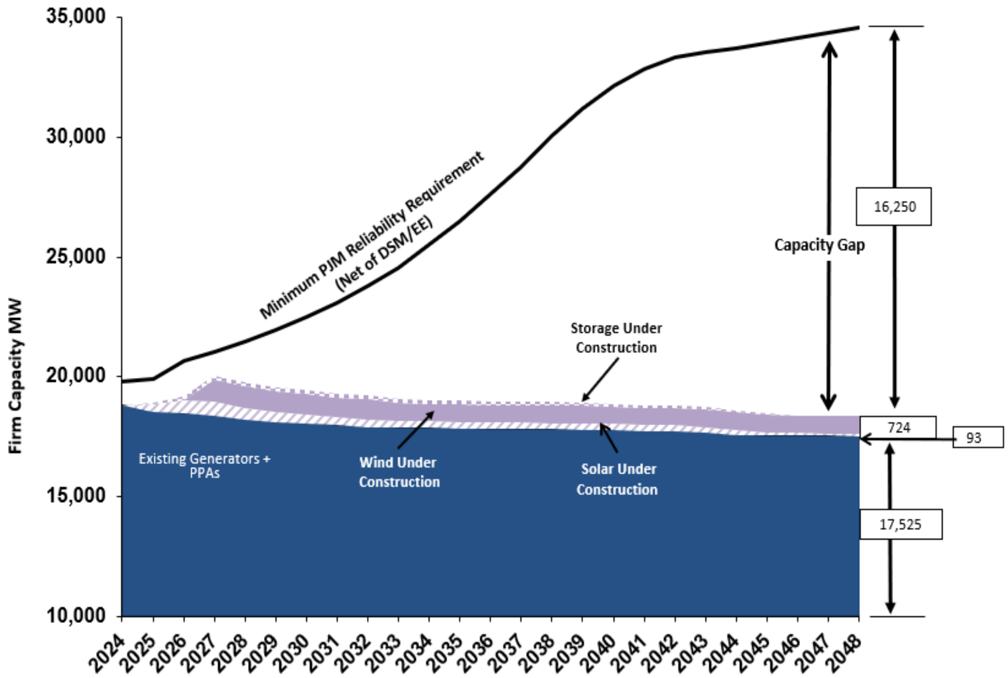
Chapter 2: Results of Integrated Planning Process

This chapter presents the results of the integrated planning process, including the Company's current positions, the Alternative Plans presented to meet the future needs of the Company's customers, the net present value ("NPV") of each Alternative Plan, and sensitivities on the Alternative Plans. This section also includes the results of the reliability analysis associated with the Alternative Plans and the results of a Virginia bill analysis.

2.1 Capacity, Energy, and REC Positions

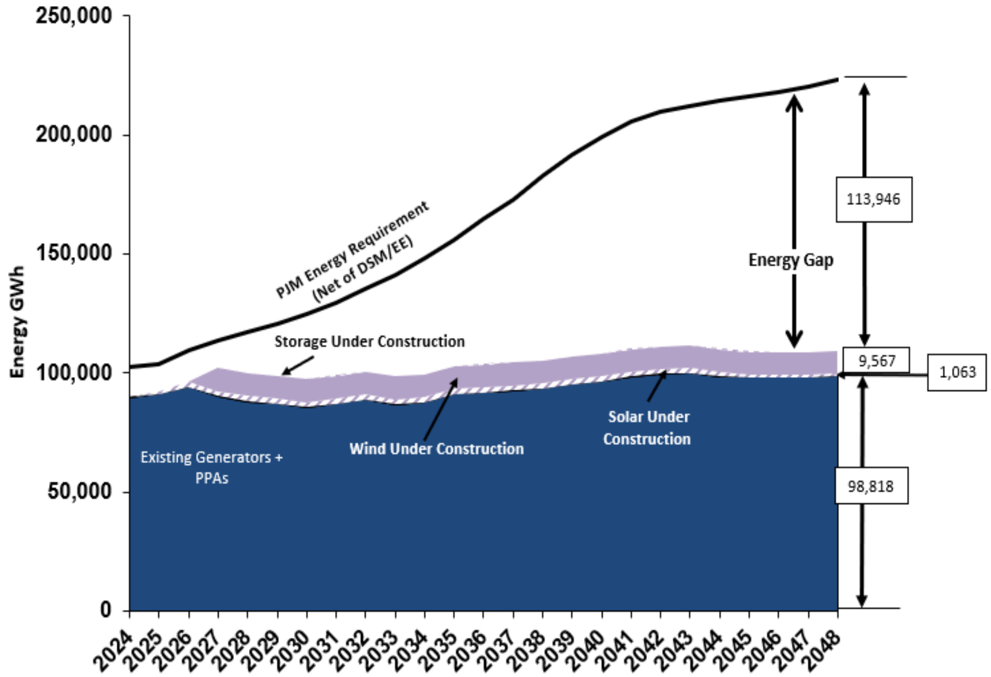
Figures 2.1.1, 2.1.2, and 2.1.3 represent the Company's current capacity (summer), energy, and REC positions under the Virginia RPS Program using unit retirement assumptions in Alternative Plan B.

Figure 2.1.1 - Current Company Summer Capacity Position with Plan B Retirement Assumptions (2024 to 2048)



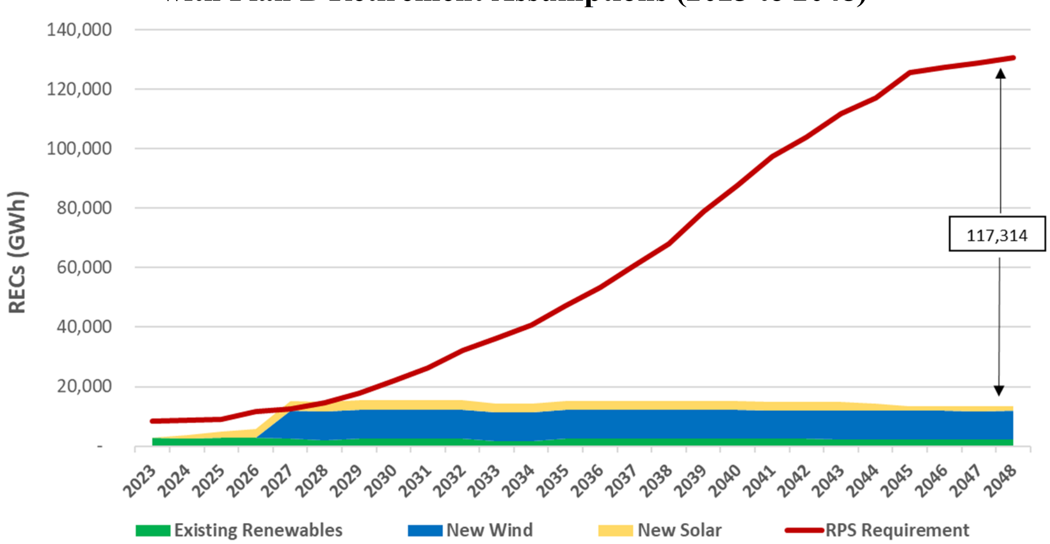
Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency.

Figure 2.1.2 – Current Company Annual Energy Position with Plan B Retirement Assumptions (2024 to 2048)



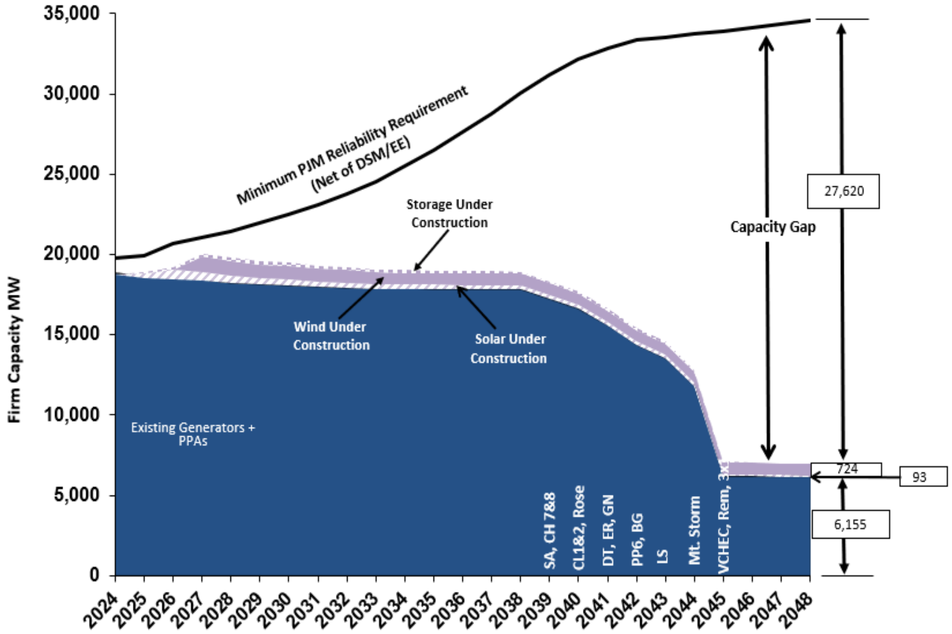
Notes: "PPAs" = power purchase agreement; "DSM" = demand side management "EE" = energy efficiency.

Figure 2.1.3: Current Company REC Position under Virginia RPS Program with Plan B Retirement Assumptions (2023 to 2048)



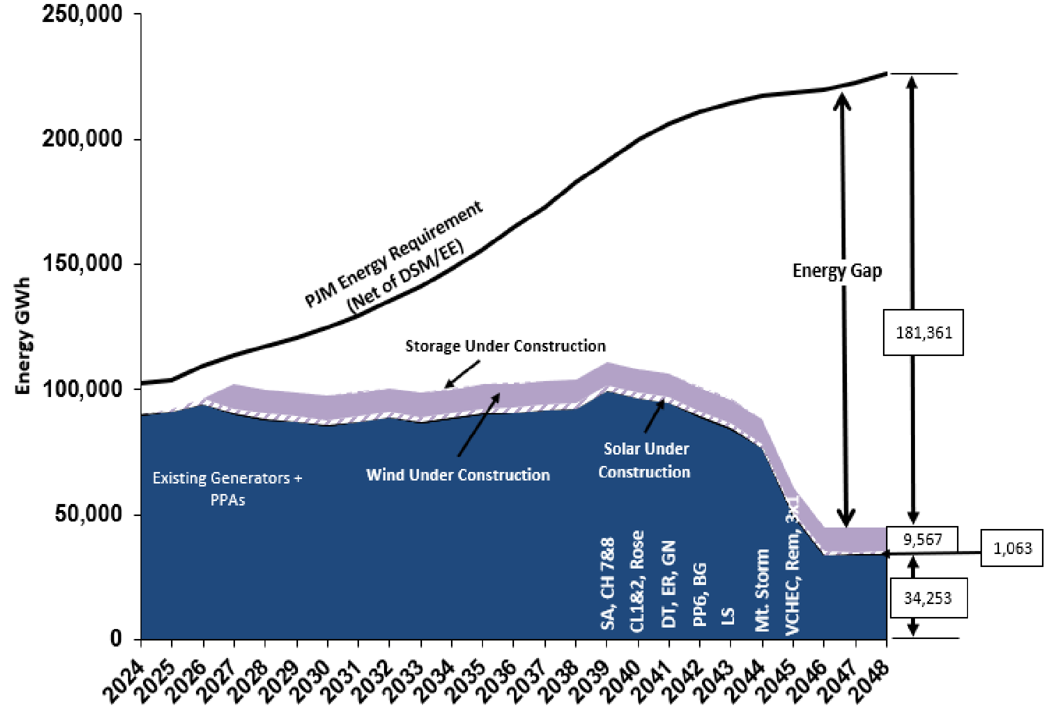
Figures 2.1.4, 2.1.5, and 2.1.6 represent the Company's current capacity (summer), energy, and REC positions under the Virginia RPS Program using unit retirement assumptions in Alternative Plan D.

Figure 2.1.4 - Current Company Summer Capacity Position with Plan D Retirement Assumptions (2024 to 2048)



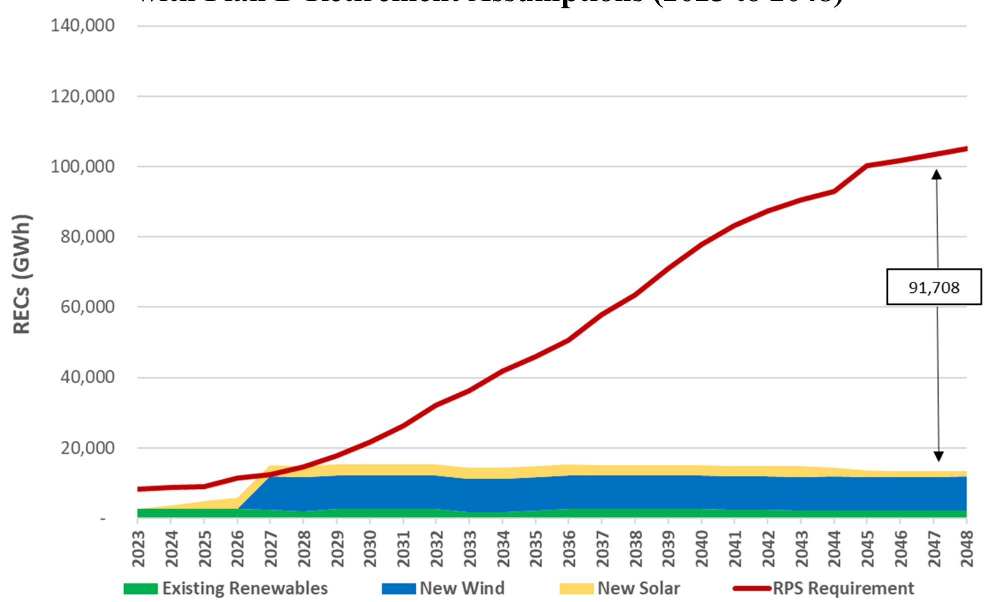
Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency; "SA" = South Anna; "CH7&8" = Chesterfield Units 7&8 (gas); "CL1&2" = Clover Units 1 & 2 (coal); "Rose"= Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas); "3x1"= Greensville, Brunswick and Warren (gas).

Figure 2.1.5 - Current Company Annual Energy Position with Plan D Retirement Assumptions (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency; "SA" = South Anna; "CH7&8" = Chesterfield Units 7&8 (gas); "CL1&2" = Clover Units 1 & 2 (coal); "Rose"= Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas); "3x1"= Greensville, Brunswick and Warren (gas).

Figure 2.1.6: Current Company REC Position under Virginia RPS Program with Plan D Retirement Assumptions (2023 to 2048)



The charts above show that both Alternative Plans B and D show a significant need for capacity, energy, and RECs throughout the Study Period. Plan B has a REC deficiency starting in 2039, while Plan D shows significant additional capacity and energy need due to unit retirements.

2.2 Alternative Plans

The 2023 Plan presents alternative paths forward for the Company to meet the future capacity and energy needs of its customers, as well as applicable requirements for procuring and retiring RECs under the Virginia RPS Program. Notably, planning work remains ongoing and necessary to test the grid under different conditions to ensure system reliability and security in the long term.

The Company's options for meeting customers' future capacity and energy needs are: (i) supply-side resources, (ii) demand-side resources, 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, incorporating input from stakeholders, and minimizing adverse environmental impact—will help the Company meet growing demand while protecting customers from a variety of potential challenges.

The Company presents five Alternative Plans designed to meet customers' needs in the future under different scenarios, which were designed using constraint-based least-cost planning techniques and proven technologies:

- <u>Plan A</u>: This Alternative Plan presents a least-cost plan that meets only applicable carbon regulations and the mandatory Virginia RPS Program. The Company presents this Alternative Plan in compliance with prior SCC and NCUC orders and for cost comparison purposes only. For Plan A, the Company did not force the model to select any specific resource and did not exclude any reasonable resource. Consistent with this directive from prior orders, the Company did not exclude carbon-emitting resources as an option to reliably meet customers' energy and capacity needs and allowed the model to select the retirement dates for existing units on a least-cost optimization basis without regard for other factors that the Company considers when evaluating unit retirements. It is important to emphasize that Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. The Company does not consider Plan A as a true alternative path forward based on these concerns, as well as the over-reliance on third-party solar PPAs to meet customer needs, which comes with risks related to accountability and project execution. It is worth noting that even in Plan A, where all of the Company's existing resources stay online, a significant amount of new development is required to meet growing customer capacity and energy needs.

- <u>Plan B</u>: This Alternative Plan includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves existing generation resources and adds an additional 2.9 GW of combustion turbine ("CT") generation to address future system reliability, stability, and energy independence issues. This allows the Company to maintain reliability while continuing to develop extensive renewable generation. Over the Study Period, this Alternative Plan includes the development of nearly 19 GW of additional solar capacity, approximately 2.6 GW of additional offshore wind capacity, 0.6 GW of new onshore wind, approximately 5.1 GW of additional energy storage capacity, and approximately 1.6 GW of SMRs. Even with the preservation of existing generation, additional CT generation, and the significant development of renewable generation, Plan B requires an increase in capacity import limits beginning in 2039 and the purchase of over 4 GW of capacity in 2041 and beyond.

- Plan C: This Alternative Plan is like Plan B in preserving existing generation and adds CT generation to address future system reliability, stability, and energy independence issues, with identical assumptions regarding the retirement of existing Company-owned carbon-emitting generation. Plan C differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.

- Plan D: This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045, resulting in zero CO_2 emissions from the Company's fleet in 2046. In order to retire these units, the Company will need to build and buy significant incremental capacity to reliably meet customer load. Plan D shows the Company building approximately 3.4 GW of incremental solar, 4.6 GW of incremental energy storage, and 3.2 GW of incremental SMRs to meet this need when compared to Plan B. Even with the additional SMRs and the preservation of 970 MW of new CT generation, assumed hydrogen capable by 2045, along with a significant incremental increase in energy storage, Plan D results in the Company purchasing over 10.8 GW of capacity and 13 GW of energy in 2045 and beyond, raising concerns about system reliability and energy independence, including reliance on out-of-state capacity to meet customer needs. In addition, there is no guarantee that other states will maintain dispatchable generation that will be available for purchase when the Company needs incremental power. This will depend greatly on the energy policy and load growth in neighboring states. Over time as more renewable energy and energy storage resources are added to the system and as other technology advances, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan D approach to maintain system reliability.

- Plan E: This Alternative Plan is like Plan D in retiring all Company-owned carbon-emitting generation by the end of 2045. Plan E differs from Plan D in that all new generation resources were selected on a least-cost optimized basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Like Plan D, under Plan E the Company would need to build and buy significant incremental capacity to reliably meet customer load. Over time as more renewable energy and energy storage resources are added to the system and as other technology advances, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan E approach to maintain system reliability.

All Alternative Plans utilize the load forecast prepared by PJM; assume a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia; and assume Virginia exits RGGI before January 1, 2024.

Figures 2.2.1 through 2.2.5 show the build plans for each Alternative Plan. The resource additions shown in these figures are incremental to existing generation and approved generation under construction, including solar and storage projects from CE-1, CE-2, and CE-3; nuclear license extensions; and nearly 2,600 MW of offshore wind.

Figure 2.2.1: Alternative Plan A (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,300	-
2025	-	-	-	-	-	-	-	1,400	-
2026	-	-	-	-	-	-	-	1,800	-
2027	900	-	-	-	-	-	-	900	-
2028	900	-	-	260	-	-	-	1,300	-
2029	900	-	-	-	-	-	-	1,700	-
2030	900	-	-	-	-	-	-	2,200	-
2031	900	-	-	60	120	-	-	2,700	-
2032	900	-	-	-	-	1,740	-	1,800	-
2033	900	-	-	-	-	-	-	2,600	-
2034	900	-	-	60	210	485	-	2,700	-
2035	900	-	-	-	-	2,225	-	1,500	-
2036	900	-	-	-	210	485	-	1,800	-
2037	900	-	-	2,660	300	485	-	1,400	-
2038	900	-	-	-	210	485	-	2,000	-
15-Year Subtotal	**10,800**	**-**	**-**	**3,040**	**1,050**	**5,905**	**-**	**27,100**	**-**
2039	900	-	-	-	270	485	-	2,400	-
2040	900	-	-	60	240	485	-	2,600	-
2041	900	-	-	-	300	1,455	-	1,600	-
2042	900	-	-	-	300	485	-	1,400	-
2043	900	-	-	60	300	485	-	900	-
2044	900	-	-	-	300	-	-	900	-
2045	900	-	-	-	300	-	-	1,000	-
2046	900	-	-	60	300	-	-	1,100	-
2047	900	-	-	-	300	-	-	1,200	-
2048	900	-	-	-	300	-	-	1,300	-
25-Year Total	**19,800**	**-**	**-**	**3,220**	**3,960**	**9,300**	**-**	**41,500**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units.

Figure 2.2.2: Alternative Plan B (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,100	-
2025	-	-	-	-	-	-	-	1,100	-
2026	-	-	-	-	-	-	-	1,600	-
2027	210	390	15	-	-	-	-	700	-
2028	231	429	30	260	90	970	-	200	-
2029	231	429	45	-	120	-	-	600	-
2030	252	468	45	-	150	-	-	900	-
2031	315	585	111	60	180	-	-	1,300	-
2032	315	585	111	-	180	-	-	1,800	-
2033	315	585	111	2,600	240	-	-	1,600	-
2034	315	585	111	60	240	-	268	1,900	-
2035	315	585	114	-	270	485	-	2,100	-
2036	315	585	114	-	300	485	268	2,100	-
2037	315	585	114	60	300	485	-	2,300	-
2038	315	585	114	-	300	485	268	2,600	-
15-Year Subtotal	**3,444**	**6,396**	**1,035**	**3,040**	**2,370**	**2,910**	**804**	**21,900**	**-**
2039	315	585	-	-	180	-	-	3,500	-
2040	315	585	-	60	300	-	268	3,900	-
2041	315	585	-	-	300	-	-	4,400	-
2042	315	585	-	-	240	-	268	4,400	-
2043	315	585	-	60	300	-	-	4,400	-
2044	315	585	-	-	300	-	268	4,200	-
2045	315	585	-	-	300	-	-	4,300	-
2046	315	585	-	60	300	-	-	4,400	-
2047	315	585	-	-	300	-	-	4,400	-
2048	315	585	-	-	300	-	-	4,600	-
25-Year Total	**6,594**	**12,246**	**1,035**	**3,220**	**5,190**	**2,910**	**1,608**	**64,400**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units.

Figure 2.2.3: Alternative Plan C (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,100	-
2025	-	-	-	-	-	-	-	1,100	-
2026	-	-	-	-	-	-	-	1,600	-
2027	315	585	-	-	-	-	-	600	-
2028	315	585	-	140	-	-	-	1,000	-
2029	315	585	-	-	-	-	-	1,500	-
2030	315	585	-	120	30	-	-	1,900	-
2031	315	585	-	60	300	-	-	2,300	-
2032	315	585	-	-	300	-	-	2,700	-
2033	315	585	-	-	300	1,455	-	1,800	-
2034	315	585	-	60	90	-	268	2,300	-
2035	315	585	-	2,600	300	-	-	2,200	-
2036	315	585	-	-	300	485	268	2,700	-
2037	315	585	-	60	300	485	-	2,700	-
2038	315	585	-	-	300	485	268	2,700	-
15-Year Subtotal	**3,780**	**7,020**	**-**	**3,040**	**2,220**	**2,910**	**804**	**28,200**	**-**
2039	315	585	-	-	300	-	-	3,500	-
2040	315	585	-	60	300	-	268	4,000	-
2041	315	585	-	-	300	-	-	4,500	-
2042	315	585	-	-	300	-	268	4,400	-
2043	315	585	-	60	300	-	-	4,400	-
2044	315	585	-	-	300	-	268	4,200	-
2045	315	585	-	-	300	-	-	4,300	-
2046	315	585	-	60	300	-	-	4,400	-
2047	315	585	-	-	300	-	-	4,400	-
2048	315	585	-	-	300	-	-	4,500	-
25-Year Total	**6,930**	**12,870**	**-**	**3,220**	**5,220**	**2,910**	**1,608**	**70,800**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units.

Figure 2.2.4: Alternative Plan D (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,100	-
2025	-	-	-	-	-	-	-	1,100	-
2026	-	-	-	-	-	-	-	1,600	-
2027	210	390	15	-	-	-	-	700	-
2028	231	429	30	260	90	970	-	200	-
2029	231	429	45	-	120	-	-	600	-
2030	252	468	45	-	150	-	-	900	-
2031	315	585	111	60	180	-	-	1,300	-
2032	315	585	111	-	180	-	-	1,800	-
2033	315	585	111	2,600	240	-	-	1,600	-
2034	315	585	111	60	240	-	-	2,200	-
2035	315	585	114	-	270	-	536	2,300	-
2036	315	585	114	-	300	-	536	2,600	-
2037	315	585	114	60	300	-	-	3,300	-
2038	315	585	114	-	300	-	536	3,800	-
15-Year Subtotal	**3,444**	**6,396**	**1,035**	**3,040**	**2,370**	**970**	**1,608**	**25,100**	**-**
2039	420	780	-	-	810	-	536	4,200	CH 7&8, SA
2040	420	780	120	60	900	-	536	4,400	CL 1&2, Rosemary
2041	420	780	120	-	900	-	536	4,800	DT, ER, GN
2042	420	780	120	-	900	-	536	5,200	PP6, BG
2043	420	780	120	60	900	-	536	5,000	LS
2044	420	780	120	-	900	-	536	5,600	Mt Storm
2045	420	780	120	-	900	-	-	10,800	3x1, VCHEC, Rem
2046	420	780	120	60	360	-	-	10,800	-
2047	420	780	120	-	360	-	-	10,800	-
2048	420	780	120	-	480	-	-	10,800	-
25-Year Total	**7,644**	**14,196**	**2,115**	**3,220**	**9,780**	**970**	**4,824**	**97,500**	**11,399**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units; "CH 7&8" = Chesterfield Units 7&8 (gas); "SA" = South Anna; "CL1&2" = Clover Units 1 & 2 (coal); Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "3x1"= Greensville, Brunswick and Warren (gas); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas).

Figure 2.2.5: Alternative Plan E (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,100	-
2025	-	-	-	-	-	-	-	1,100	-
2026	-	-	-	-	-	-	-	1,600	-
2027	315	585	-	-	-	-	-	600	-
2028	315	585	-	140	-	-	-	1,000	-
2029	315	585	-	-	210	-	-	1,300	-
2030	315	585	-	120	300	-	-	1,400	-
2031	315	585	-	60	300	-	-	1,800	-
2032	315	585	54	-	300	-	-	2,200	-
2033	315	585	120	-	300	-	-	2,700	-
2034	315	585	-	60	300	970	-	2,300	-
2035	315	585	-	2,600	300	-	-	2,200	-
2036	315	585	-	-	300	-	268	2,700	-
2037	315	585	-	60	300	-	268	3,300	-
2038	315	585	120	-	300	-	536	3,800	-
15-Year Subtotal	**3,780**	**7,020**	**294**	**3,040**	**2,910**	**970**	**1,072**	**29,100**	**-**
2039	420	780	120	-	900	-	536	4,100	CH 7&8, SA
2040	420	780	120	60	900	-	536	4,300	CL 1&2, Rosemary
2041	420	780	120	-	900	-	536	4,800	DT, ER, GN
2042	420	780	120	-	900	-	536	5,200	PP6, BG
2043	420	780	120	60	900	-	536	4,900	LS
2044	420	780	120	-	900	-	536	5,600	Mt Storm
2045	420	780	120	-	900	-	-	10,800	3x1, VCHEC, Rem
2046	420	780	120	60	360	-	-	10,800	-
2047	420	780	120	-	750	-	-	10,500	-
2048	420	780	120	-	30	-	-	10,800	-
25-Year Total	**7,980**	**14,820**	**1,494**	**3,220**	**10,350**	**970**	**4,288**	**100,900**	**11,399**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units; "CH 7&8" = Chesterfield Units 7&8 (gas); "SA" = South Anna; "CL1&2" = Clover Units 1 & 2 (coal); Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "3x1"= Greensville, Brunswick and Warren (gas); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas).

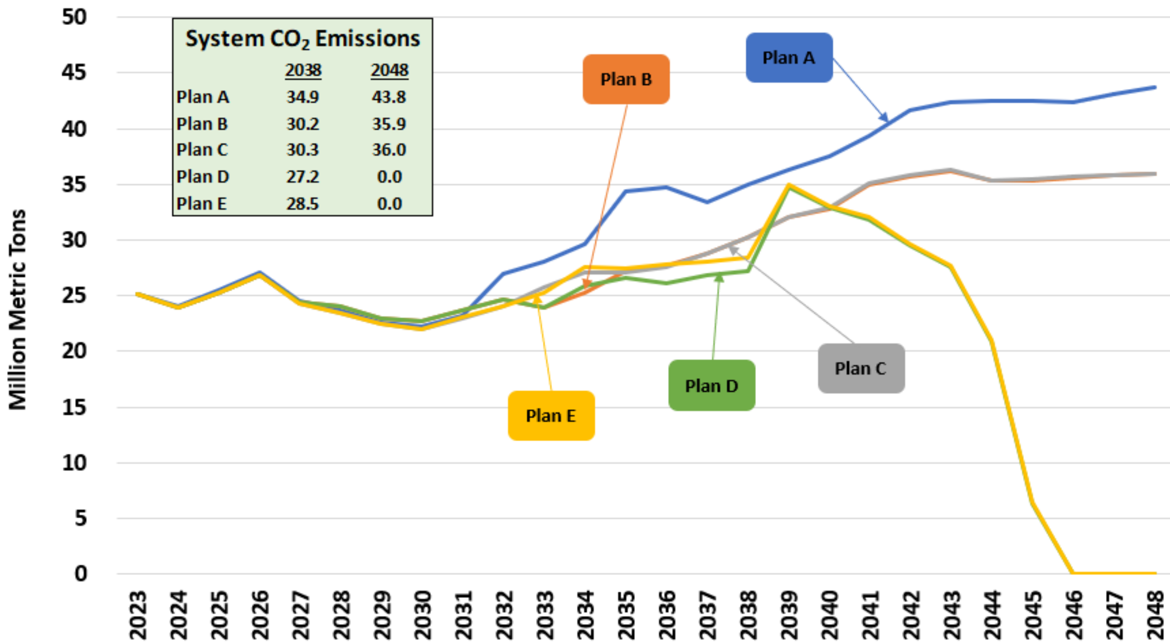
Charts showing the capacity (summer), energy, and REC positions assuming the build plans shown in each Alternative Plans are provided in Appendix 2A. Winter capacity charts for each Alternative Plan are provided in Appendix 5T. Solar resources provide little capacity for winter peaks, while wind, nuclear and fossil resources produce more in the winter than in the summer. A diverse resource mix will ensure that the Company is able to meet the needs of customers during extreme weather events in both the summer and winter months.

The SCC directed the Company to consider market purchases during the winter from the PJM wholesale market or from merchant generators located in the DOM Zone. The Company is concerned that overreliance on the market for purchases could present issues if other states within PJM build significant amounts of solar generation and those zones expect the market to provide energy at the same time the Company is expecting that energy (*e.g.*, extended cloudy winter periods). If that were to become reality, either energy shortages or extreme price spikes would occur. Concerning purchases from merchant generators located within the DOM Zone, those generators would likely be needed to meet the non-DOM LSE load within DOM Zone~~, which is also winter peaking~~. The merchant generators located within the DOM Zone are likely also committed to PJM or specific customers. That said, this is not public information, making it difficult for the Company to incorporate those potential resources into its planning. See Appendix 2B for the capacity-related information directed by the SCC.

All Alternative Plans show that a growing capacity and energy need will require a diverse mix of resources and an increased reliance on market purchases, even under normal weather conditions and with very few unit retirements. These plans demonstrate that solar, wind, and storage will be the majority of the Company's generation development over the next fifteen years. Until new zero carbon dispatchable generation options are developed or reach commercial viability, gas units are among the most affordable and reliable options for new generation that can quickly adjust output with changes in intermittent output. With normal weather modeling in Plans A, C, and E these combustion turbine facilities were economically selected by the model by 2035 at the latest. However, to address energy and capacity needs during more extreme weather scenarios, especially in the winter, the Company included 970 MW of new CT generation as early as 2028 in Plans B and D. These units will be capable of blending hydrogen in the future and critical to meeting grid reliability needs much sooner than 2035.

Figure 2.2.6 shows projected CO_2 emissions from the Company's fleet for the duration of the Study Period. Due the changes in retirements, as well as higher capacity factors for the Company's existing generators driven by the higher 2023 PJM Load Forecast, carbon emission projections are increasing. Both the build plans and the carbon projections in all five Alternative Plans are similar for the first ten years. While Plans D and E show no Scope 1 emissions by 2045, the level of purchased power required to make the necessary retirements possible would have a Scope 3 emissions impact. ICF Resources, LLC ("ICF") forecasts show gas remaining as the margin generator throughout the Study Period. Through the energy transition, the Company will continue to monitor PJM Margin Emissions rates and evaluate the regional emissions impacts of running existing units versus relying on purchasing power from the market.

Figure 2.2.6 – System CO_2 Output from Company Fleet for Alternative Plans (based on current technology)



2.3 Reliability Analyses of Alternative Plans

The Company completed a high-level assessment of the potential reliability of the Company's transmission system under the build plans shown in Alternative Plans A through E, with the goal of identifying any potential reliability concerns. A significant factor in future transmission system reliability is the retirement of synchronous generation facilities. Based on the complexity and the time it takes to complete this type of analysis, the Company used preliminary versions of Alternative Plans A through E in this 2023 Plan, the 2022 PJM Load Forecast, and the 2022 model series for 2035 and 2045 for the reliability studies. Given the significant increase in load in the 2023 PJM Load Forecast compared to the 2022 PJM Load Forecast, the potential reliability concerns identified are likely understated. The Company provides a summary of its assessment here, with additional details provided in Chapter 7:

- Plan A: The Company does not have significant transmission system reliability concerns under the build plan shown in Plan A. While Plan A includes a significant amount of new intermittent solar generation, Plan A also maintains the majority of the Company's existing fleet of synchronous generation facilities and constructs additional quick-start and dispatchable combustion turbines, both of which would help the transmission system maintain reliability and continue to run similarly to how it runs today.

- Plan B: The Company does not have significant transmission system reliability concerns under the build plan shown in Plan B. Plan B includes a significant amount of new intermittent renewables compared to Plan A. However, Plan B also maintains a large amount of the Company's existing fleet of synchronous generation facilities and includes the addition of new SMRs. The combination of existing generation and the new SMRs help the transmission system maintain reliability and continue to run similarly to how it runs today. Notably, Plan B incorporates approximately $6 billion of transmission infrastructure to account for the higher level of imports needed to meet demand by 2040.

- Plan C: The Company does not have significant transmission system reliability concerns under the build plan shown in Plan C, as it only varies from Plan B minimally.

- Plan D: The Company has system reliability concerns under the build plan shown in Plan D due to the retirement of all carbon-emitting units—the traditional synchronous generators relied on for system reliability—by the end of 2045. The Company's analysis showed suboptimal primary frequency and inertia response following the retirement of a large synchronous generation. The average fault current over the Company system decreased when compared to Plans A, B, and C. Notably, Plan D incorporates approximately $10.9 billion of transmission infrastructure to account for the higher level of imports needed to meet demand.

- Plan E: The Company has the same system reliability concerns under the build plan shown in Plan E, which varies from Plan D minimally.

2.4 NPV Results

The Company evaluated the Alternative Plans to compare the NPV utility costs for each build plan over the Study Period. Figure 2.4.1 presents these NPV results on the "Total System Costs" line, as well as the estimated NPV of proposed investments in the Company's transmission and distribution systems, broken down by specific line item.

Figure 2.4.1 – NPV Results

($B)	Plan A	Plan B	Plan C	Plan D	Plan E
Total System Costs	$88.5	$100.2	$99.7	$108.8	$105.8
Grid Transformation Plan (Net of Benefits)	$(1.6)	$(1.6)	$(1.6)	$(1.6)	$(1.6)
Strategic Underground Program	$0.7	$0.7	$0.7	$0.7	$0.7
Transmission	$22.2	$28.4	$28.4	$33.1	$33.1
Total Plan NPV	**$109.7**	**$127.7**	**$127.2**	**$140.9**	**$138.0**
Plan Delta vs. Plan A	$ -	$ 18.0	$17.5	$31.2	$ 28.3

Notes: As previously ordered by the SCC, this figure includes incremental cost estimates associated with transmission and distribution investments. All costs are estimates and will vary based on the actual generation, transmission, and distribution infrastructure developed to meet customer needs. (1) Total system costs include the results from Figures 2.2.1 through 2.2.5 plus approved, proposed, future, and generic DSM, as applicable; costs related to environmental laws and regulations; renewable energy integration costs; and REC banking as discussed in Section 4.7.4, ***REC-Related Assumptions***. (2) All NPVs are calculated with a 6.52% discount rate. (3) Numbers may not add due to rounding.

2.5 Virginia Consolidated Bill Analysis

The Company completed a consolidated bill analysis for each Alternative Plan presented in the 2023 Plan. This analysis encompasses three different customer classes and spans 2019 through 2035.

The Company calculated projected bills for each customer class under each Alternative Plan based on requirements set by the SCC ("Directed Methodology"). These requirements direct that the Company use constant class allocation factors across time and no sales growth, either at the system or class level, in its calculations. As discussed in prior proceedings, the Company believes that this methodology results in overstated bill projections because it does not reflect anticipated growth in sales over the period on which each build plan is based.

Given these concerns with the Directed Methodology, the Company has also calculated projected bills under each Alternative Plan using a forecasted system and class sales growth and the associated class allocation factors ("Company Methodology").

The electric bill of the Company's typical residential customer in Virginia (*i.e.*, one that uses 1,000 kWh per month) was $122.66 as of December 31, 2019. As of May 1, 2020, this typical bill was $116.18, with the decrease largely attributable to a significant reduction in the fuel factor. Figure 2.5.1 presents the summary results of typical residential customer bill projections under both the Company Methodology and the Directed Methodology based on Alternative Plan B for 2030 and 2035.

Figure 2.5.1 shows that, when using the Company Methodology and a baseline of May 1, 2020, the typical residential customer's bill is expected to increase at a compound annual growth rate ("CAGR") of 2.6% through 2035. When using the Company Methodology and December 31, 2019, as the baseline, the projected increase in the typical residential customer's bill is approximately 2.2% on a compound annual basis.

As an additional point of comparison, in July 2008—the year following passage of the Virginia Electric Utility Regulation Act—the electric bill of the Company's typical residential customer in Virginia was $107.20. Using 2008 as the baseline, the projected CAGR for the typical residential customer bill through 2035 is approximately 1.8% using the Company Methodology.

Figure 2.5.1: Residential Bill Projection (1,000 kWh per Month)

	Plan B – Company Methodology (includes load growth)			Plan B – Directed Methodology (excludes load growth)		
	Projected Bill	CAGR Dec. 2019	CAGR May 2020	Projected Bill	CAGR Dec. 2019	CAGR May 2020
Dec. 31, 2019	$122.66			$122.66		
May 1, 2020	$116.18			$116.18		
Year End 2030	$167.34	2.9%	3.5%	$193.12	4.2%	4.9%
Year End 2035	$174.15	2.2%	2.6%	$235.40	4.2%	4.6%
Total Bill Increase (May 2020-2035)	$57.97			$119.22		

Note: Derived using the system resources selected in Alternative Plan B incorporating the Company Methodology for the purposes of the future billing analysis, including forecasted sales growth and forecasted class allocation factors.

The typical Company residential customer in Virginia (*i.e.*, one who uses 1,000 kilowatt-hours of electricity per month) pays $140.25 as of January 1, 2023, which on a per-unit basis is approximately 14.03 cents per kilowatt-hour ("¢/kWh"). This figure compares favorably to the national average (15.47¢/kWh) and the regional averages for the South Atlantic (14.04¢/kWh), Middle Atlantic (19.86¢/kWh), and New England (29.74¢/kWh) states as reported in the U.S. Energy Information Administration's ("EIA") electric power monthly release with data for January 2023.

2.6 Sensitivity Analyses

The Company conducted several sensitivities for this 2023 Plan to show the potential paths forward under different future conditions consistent with SCC and NCUC requirements. For all sensitivities, the Company re-optimized the build plans applying different assumptions.

First, the Company conducted sensitivities related to RGGI based on the uncertainty discussed in Section 5.2.3, ***Environmental Regulations***. The base assumptions for Alternative Plans A through E all use a commodity price forecast that assumes Virginia exits RGGI before January 1, 2024. For its sensitivity analyses, the Company used a commodity price forecast that assumes Virginia stays in RGGI and includes a RGGI-related cost adder on all Virginia carbon-emitting generators. Figure 2.6.1 compares the Alternative Plans under their base case assumptions with the Alternative Plan assuming Virginia stays in RGGI. As the table shows, it would be more expensive for customers if Virginia remains in RGGI, while making a negligible difference in the Company's carbon emissions.

Figure 2.6.1: 2023 Plan Sensitivities on Virginia in RGGI

Plan	NPV Total ($B)		Approximate CO_2 Emissions from Company in 2048 (Metric Tons)	
	Base Plan	Va. in RGGI	Base Plan	Va. in RGGI
Plan A	$109.7	$111.5	43.8 M	43.5 M
Plan B	$127.7	$129.3	35.9 M	35.8 M
Plan C	$127.2	$129.1	36.0 M	35.9 M
Plan D	$140.9	$142.5	0	0
Plan E	$138.0	$139.7	0	0

Second, the Company conducted sensitivities using different load forecasts. As discussed above, Alternative Plan B utilizes the 2023 PJM Load Forecast. The Company increased and decreased the 2023 PJM Load Forecast by 5% to show the build plans under high and low load forecast scenarios. The Company also ran a sensitivity using the 2023 Company Load Forecast. Finally, the Company ran a sensitivity reflecting only approved energy efficiency programs as required by the SCC. Figure 2.6.2 shows the results of these sensitivities.

Figure 2.6.2: 2023 Plan Sensitivities on Load Forecast

	Plan B (PJM Load Forecast)	Plan B with PJM High Load Forecast	Plan B with PJM Low Load Forecast	Plan B with Company Load Forecast	Plan B with Approved Energy Efficiency
NPV Total ($B)	$127.7	$137.9	$110.2	$129.7	$127.8
Approximate CO_2 Emissions from Company in 2048 (Metric Tons)	35.9 M	39.2 M	34.5 M	38.7 M	38.6 M
Solar (MW)	10,875 15-yr 19,875 25-yr	10,875 15-yr 20,475 25-yr	10,875 15-yr 19,917 25-yr	10,875 15-yr 19,875 25-yr	10,875 15-yr 20,235 25-yr
Wind (MW)	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr
Storage (MW)	2,370 15-yr 5,190 25-yr	2,370 15-yr 4,170 25-yr	2,370 15-yr 4,050 25-yr	2,370 15-yr 5,040 25-yr	2,370 15-yr 5,370 25-yr
Nuclear (MW)	804 15-yr 1,608 25-yr	804 15-yr 1,608 25-yr	268 15-yr 536 25-yr	536 15-yr 1,340 25-yr	485 15-yr 1,940 25-yr
Natural Gas Fired (MW)	2,910 15-yr 2,910 25-yr	2,425 15-yr 2,910 25-yr	1,455 15-yr 2,910 25-yr	2,910 15-yr 2,910 25-yr	1,455 15-yr 2,910 25-yr
Retirements (MW)	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr

Third, the Company ran input variations on Alternative Plan B to show the effect on NPV using a range of possible costs. The Company first ran a sensitivity using different commodity price forecasts. To provide sensitivities on fuel, energy, capacity, and REC prices, the Company used two commodity price forecasts produced by ICF—the High Fuel Price commodity forecast and the Low Fuel Price commodity forecast. See Section 4.4, ***Commodity Price Assumptions***, for a description of these forecasts and the interrelated nature of these commodity prices. The Company then ran a sensitivity that increased and decreased the projected capital construction costs of different resources by 10%. The Company also ran a sensitivity showing all solar resources at a projected design capacity factor instead of the lower of the design capacity factor or the three-year historical average capacity factor of the Company's existing solar fleet in Virginia. Figure 2.6.3 shows the summarized results of this group of sensitivities.

Figure 2.6.3: 2023 Plan Sensitivities on NPV Costs

Plan Description	NPV Total ($B)
Plan B	$127.7
Plan B: High Fuel Prices	$143.4
Plan B: Low Fuel Prices	$124.9
Plan B: High Capital Construction Costs	$134.7
Plan B: Low Capital Construction Costs	$124.0
Plan B: Solar Design Capacity Factor	$126.9

Chapter 3: Short-Term Action Plan

The short-term action plan provides the Company's strategic plan for the next five years (2024 to 2029). The Company plans to proactively position itself in the short-term to meet its commitment to clean energy for the benefit of all stakeholders over the long term. The Company also plans to continue its analyses on how to meet both its clean energy goals and the requirements of the VCEA while continuing to provide safe, reliable, and affordable service to its customers.

3.1 Generation

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

- File annual plans for the development of solar, onshore wind, and energy storage resources consistent with the requirements established by the VCEA, including related requests for approval of CPCNs and for prudence determinations related to PPAs;
- Complete construction of CVOW with a target in-service date of late 2026;
- Continue construction and begin operation of approved solar and storage projects;
- Meet targets under Virginia's mandatory RPS Program at a reasonable cost and in a prudent manner, and submit annual compliance certification to the SCC;
- Meet target under North Carolina's renewable energy portfolio standard at a reasonable cost and in a prudent manner, and submit its annual compliance report and compliance plan to the NCUC;
- Support ongoing NRC review of the subsequent license renewal application for North Anna Units 1 and 2;
- Continue development work for 970 MW of new gas-fired CTs, see Section 5.4.2, ***Combustion Turbines***;
- Begin development of a backup LNG facility to support reliable operations of the Company's Greensville Power Station and possibly other stations;
- Continue to make investments at existing generation units needed to comply with environmental regulations;
- Evaluate opportunities for uprates or increased capacity injection rights ("CIRs") at existing units;
- Continue to evaluate potential unit retirements or replacement of existing units in light of changing market conditions and regulatory requirements; and
- Continue to evaluate pilot energy storage projects associated with the battery storage pilot program established by the Grid Transformation and Securities Act of 2018 ("GTSA").

Appendices 3A and 3B provide further details on each generation project under construction and under development, respectively. The Company has not discontinued its pursuit of any potential supply-side resources over the short-term since the 2020 Plan, the projected dates and nameplate capacity in each year has simply shifted with actual development activity.

3.2 Demand-Side Management

Over the next five years, the Company will continue to identify and propose new, revised, or bundled DSM programs that work towards the spending targets of the GTSA and the energy savings targets of the VCEA in conjunction with the established DSM stakeholder process and the recommendations from the Company's long-term DSM plan. The Company is currently conducting an appliance saturation study and, once completed, will begin a new DSM market potential study in 2023, with results expected in early 2024.

In Virginia, the Company filed its Phase XI DSM application in December 2022, seeking approval of five new DSM programs (one of which is a pilot) and four new program bundles. The SCC is expected to issue its final order on the application in August 2023.

In North Carolina, the Company will continue its analysis of future programs and will file for approval in North Carolina for those programs that continue to meet Company requirements for new DSM resources and have been approved in Virginia, while also meeting the expectations of the NCUC regarding cost-effectiveness.

3.3 Transmission

Over the next five years, the Company will continue to assess its transmission system and construct facilities required to meet the needs of its customers. Generally, the Company anticipates transmission facilities will be needed to rebuild aging infrastructure, interconnect data center customers, address reliability criteria violations, and interconnect new renewable energy projects. Appendix 3C provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM. Appendix 7A lists the transmission lines under construction.

The Company will also continue its work to study the transmission system reliability needs resulting from the addition of significant renewable energy resources and the potential retirement of synchronous generator facilities, as discussed in Chapter 7.

3.4 Distribution

Over the next five years, the Company will continue to assess its distribution grid, adapt the distribution grid to meet the needs of a modernized system, and implement solutions and programs to meet the needs of its customers both today and in the future. Specifically, the Company expects to take the following actions related to its distribution grid:

- Continue implementing the Grid Transformation Plan, including initiatives to facilitate the integration of DERs, enhance distribution grid reliability, resiliency, and security, and improve the customer experience;
- Continue publishing hosting capacity maps for utility-scale DERs, net metering DERs, and transportation electrification;
- Explore the use of energy storage systems as non-wires alternatives for distribution grid support using a standardized screening process;
- Continue developing integrated distribution planning capabilities, including advancing load and DER forecasting capabilities;
- Continue its Strategic Undergrounding Program ("SUP");
- Continue to expand EV program offerings for customers;
- Continue to pilot vehicle-to-grid technology through the Electric School Bus Program;
- Continue to pilot battery energy storage systems ("BESS") as grid support and resiliency resources; and

- Expand its rural broadband program to bridge the digital divide and serve the unserved communities in Virginia.

Chapter 4: Generation – Planning Assumptions

The generation planning process begins with the development of a long-term annual peak and energy requirements forecast. Next, existing and approved supply- and demand-side resources 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. The Company also completes a retirement analysis on certain existing generating resources to determine the feasibility of continuing to maintain and operate those resources. Next, a feasibility screening is conducted to identify a set of future supply-side resources potentially available to the Company, along with their individual characteristics, using input assumptions such as fuel prices, emissions costs, maintenance costs, and resource costs. Additionally, the Company incorporates the cost-benefit screening used 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 PLEXOS model—a utility modeling and resource optimization tool—along with any regulatory requirements (*e.g.*, the requirements in the Virginia RPS Program) and reasonable constraints (*e.g.*, capacity import limits). The Company then develops a set of alternative plans using PLEXOS that represent future paths forward considering the major drivers of future uncertainty. The Company develops these alternative plans in order to test different resource strategies against scenarios that may occur given future market and regulatory uncertainty. The NPV system costs from PLEXOS include the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs of future resources.

The Company currently models its system in PLEXOS based on hourly data. This 2023 Plan does not incorporate sub-hourly analysis because of the challenge the Company faced to solve the model with a significantly higher load forecast. Especially for net zero modeling, a single model run could take as long as 18 hours to solve with hourly data. Sub-hourly analysis will require sub-hourly inputs based on historical performance for all resource types that could represent the operating characteristics of those resources for future projections. In addition, the Company must use internal information to establish the adjusted reserve margin and coincidence factor, because PJM does not provide this level of detail. Additionally, sub-hourly pricing would be very difficult to accurately predict and significantly increase the cost of forecasting. Nevertheless, the Company will continue to consider sub-hourly analysis in future Plans and update filings once the required inputs and processes are developed and validated. Sub-hourly analysis would capture the potential benefits from ancillary service markets. For example, sub-hourly analysis would be able to capture the benefits that battery energy storage systems could offer to the regulating services.

In this 2023 Plan, the Company relies on several assumptions for its integrated resource planning process. This chapter discusses these assumptions related to load forecasting, capacity market, commodity prices, construction costs, federal tax credits, new resource, carbon, and modeling. The Company updates its assumptions annually to maintain a current view of relevant markets, the economy, and regulatory drivers.

4.1 Load Forecast

The 2023 Plan presents two load forecasts: (i) the 2023 PJM Derived Load Forecast and (ii) the 2023 Company Load Forecast. The 2023 PJM Derived Load Forecast was used in the development of all Alternative Plans. However, because of the limited nature of the information provided by PJM, as well as reasons described in Section 1.1, ***PJM Load Forecast and Energy Transition Risks***, the Company presents and discusses the 2023 Company Load Forecast as well and presents a sensitivity using the Company Load Forecast. Figures 4.1.1 and 4.1.2 compare these two load forecasts and provide historical peak load and energy. Note that historical data in the charts is not weather normalized and is also not adjusted for retail choice. Both load forecasts include a downward post-model adjustment for energy efficiency and retail choice, as described further in Section 4.1.3, ***Energy Efficiency Adjustment***, and Section 4.1.4, ***Retail Choice Adjustment***, respectively.

Overall, the 2023 PJM Derived Load Forecast anticipates summer peak demand and energy CAGR for the DOM LSE of approximately 2.9% and 4.2%, respectively, over the Planning Period. The 2023 Company Load Forecast anticipates DOM DEV LSE summer peak demand and energy forecast CAGR of 3.2% and 4.2%, respectively.

Figure 4.1.1 - DOM LSE Non-Coincident Peak Load Forecast Comparison

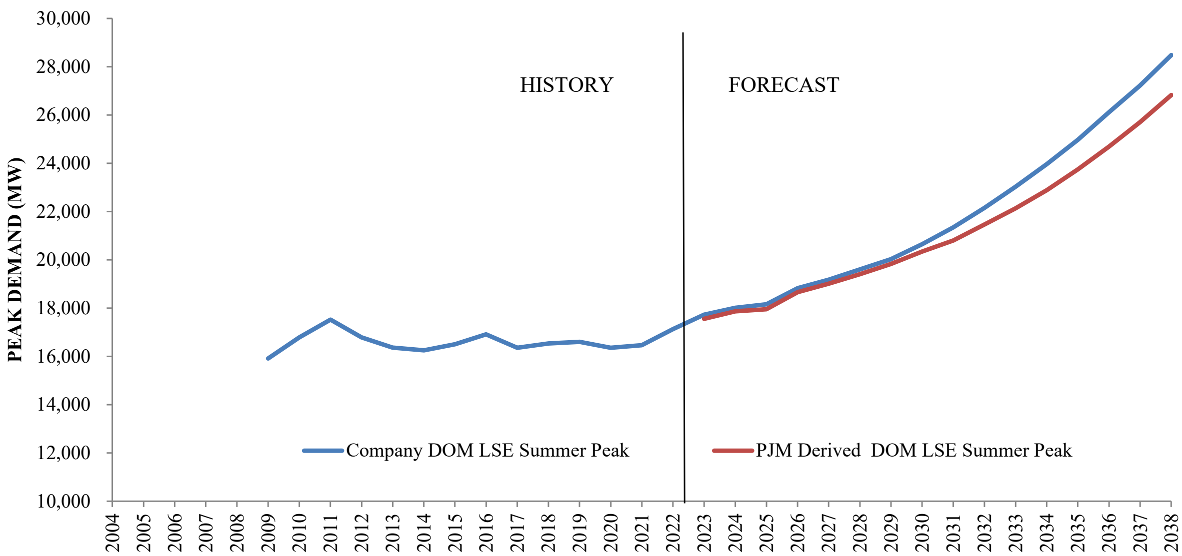
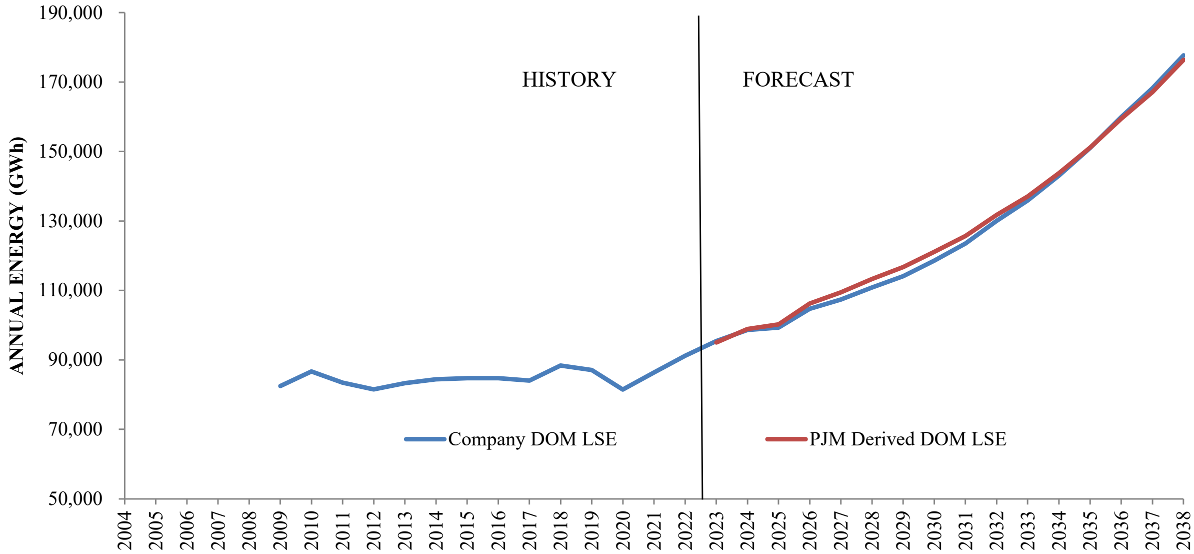


Figure 4.1.2 - DOM LSE Annual Energy Comparison



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 4A through 4F. Appendix 4G provides a summary of the summer and winter peaks used in the Company Load Forecast. 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 4H. Appendix 4I provides the reserve margins for a 3-year actual and 15-year forecast, and Appendix 4J provides the 3-year actual and 15-year forecast summer and winter peaks to show seasonal load. Finally, the 3-year historical load for wholesale customers is provided in Appendix 4K. See Appendix 4L for load duration curves for the years 2023, 2028, and 2038 with and without DSM. The information provided in Appendices 4A through 4F and 4K use the Company Load Forecast because PJM does not provide this level of detail.

4.1.1 PJM Derived Load Forecast

The Company utilized the DOM Zone load forecast as published by PJM in its 2023 PJM Load Forecast Report dated January 2023 in the development of all Alternative Plans included in this 2023 Plan. The PJM website (www.PJM.com) contains information on the methods used by PJM in developing this forecast.

To properly use the PJM load forecast in the development of this 2023 Plan, the Company needed to adjust that forecast for modeling purposes. Since PJM does not provide a DOM LSE forecast, the Company first scaled down the PJM DOM Zone coincident peak load forecast and energy forecast, and then extended it. The Company completed this in two parts. First, the Company adjusted the forecast by taking out PJM's DOM Zone data center forecast. This was then adjusted down by utilizing comparable historical DOM LSE to DOM Zone load ratio. The Company then adds back the data center forecast and makes a downward adjustment for retail choice customers and energy efficiency forecasts. This method of scaling down of PJM forecast ensures that the DOM LSE to DOM Zone ratios change in the forecast period appropriately. The Company then extended the scaled-down non-data center forecast based on the 15-year growth rate and extended the DOM LSE-level data center forecast using the Company's forecast of declining annual increases, levelling off at 1% annually in 2043 and beyond. Finally, the Company added these two components together.

Figure 4.1.1.1 presents the 2023 PJM Derived Load forecast. The resulting summer peak demand and energy CAGRs are 2.3% and 3.3%, respectively, between 2023 and 2048. Because PJM considers the DOM Zone to be a summer peaking zone, the Company developed this 2023 Plan using a summer peak to align with PJM's DOM Zone summer coincident peak demand and energy forecast.

Figure 4.1.1.1: 2023 PJM Load Forecast Adjusted to LSE Requirements

Year	DOM Zone Coincident Peak (MW)	DOM LSE Equivalent (MW)	DOM Zone Energy (GWh)	DOM LSE Equivalent (GWh)
2023	21,274	16,998	120,495	94,996
2024	22,126	17,266	128,855	98,886
2025	23,058	17,348	136,328	100,205
2026	24,823	18,019	150,796	106,193
2027	26,375	18,341	163,997	109,451
2028	27,906	18,715	177,605	113,308
2029	29,414	19,133	189,774	116,689
2030	30,794	19,622	201,819	121,115
2031	32,276	20,129	214,320	125,692
2032	33,641	20,752	226,951	131,712
2033	34,957	21,415	237,408	137,118
2034	36,221	22,235	247,810	143,789
2035	37,367	23,104	257,503	151,151
2036	38,517	24,059	267,876	159,434
2037	39,690	25,050	276,725	167,093
2038	40,998	26,193	287,188	176,427
2039		27,166		184,689
2040		28,017		192,019
2041		28,653		197,186
2042		29,084		200,851
2043		29,247		202,521
2044		29,396		204,543
2045		29,587		205,902
2046		29,767		207,618
2047		29,954		209,350
2048		30,159		211,450

Note: For years 2039 to 2048, the Company calculated the DOM LSE forecast by adding the scaled-down non-data center forecast extended based on the 15-year growth rate with the DOM LSE-level data center forecast extended using the Company's declining data center growth rate forecast.

Overall, the 2023 PJM Load Forecast (published in January 2023) anticipates that summer peak demand and net energy for the DOM Zone will increase at a CAGR of approximately 4.4% and 6.0%, respectively, between 2023 and 2038. This is markedly different from the 2022 PJM Load Forecast that showed an increase at a CAGR of approximately 2.0% and 2.9%, respectively, between 2022 and 2037. The key drivers for the forecast change are addressed in Section 1.1, ***PJM Load Forecast and Energy Transition Risks***.

4.1.2 Company Load Forecast

The 2023 Plan also includes the Company's internally developed peak demand and energy forecast. The Company ran a sensitivity on Alternative Plan B using this internally developed forecast instead of the PJM Derived Load Forecast, the results of which are shown in Section 2.6, ***Sensitivity Analyses***.

While the Company forecast and 2023 PJM forecast are in general alignment, the Company continues to believe that its forecast is more appropriate to use than PJM's forecast. Because the Company forecasts sales and associated drivers at customer class level, the resulting forecast is better able to capture region-specific load characteristics. As an example, PJM's forecast incorporates DSM reductions, but does not specifically incorporate Company DSM programs or VCEA targets. While the Company attempts to account for VCEA targets in going from PJM Derived forecast, it does so without any regard for DSM already embedded in PJM's original DOM Zone forecast. As another example, the Company has conducted a study to forecast EVs in its service territory, PJM has not been able to conduct such detailed study for each of its load zones. Additionally, since PJM's forecast is prepared in the last quarter of the year, as new information becomes available, the Company's planning process wouldn't be able to incorporate those changes in its base case. This could potentially have a more significant impact as the Company shifts to an October 15 deadline for its Plans using a January PJM load forecast. Finally, there are several complexities encountered in converting the forecast from DOM Zone to DOM LSE that are avoided by directly modeling the Company load, as done in the Company forecast. These are some of the key reasons that support using the Company's load forecast as opposed to PJM's in the long-term planning process.

At a high level, the Company's load forecast is prepared using Company sales data and DOM LSE peak and energy data. The sales data is adjusted by excluding data center sales and adding back retail choice sales. The sales forecast process is described in the subsection titled ***Methodology*** later in this section. The resulting sales forecast is then converted into an energy forecast using a historical regression analysis of energy and sales. This is then followed by post-processing forecast adjustments for data centers, retail choice sales, energy efficiency, behind-the-meter solar and EVs. Finally, peak forecast is derived as described in the subsection titled ***Methodology*** below. Figure 4.1.2.1 presents the 2023 Company Load Forecast. Overall, the Company anticipates DOM LSE summer peak demand and energy forecast CAGRs of 2.6% and 3.4%, respectively, between 2023 and 2048.

The primary refinements that the Company has made to its internal load forecasting methodology since the 2020 Plan are as follows:

- DOM LSE sales, energy, and peak are now modeled directly. In the 2020 Plan, the Company instead modeled the DOM Zone and then derived DOM LSE by utilizing a DOM LSE to DOM Zone ratio.

- DOM LSE peak load is now derived using an hourly model incorporating variables from the Company's Sales Model. Use of an hourly peak model is consistent with PJM's new peak forecast methodology.

- Usage per customer is now modeled directly as opposed to modeling total residential sales. Residential sales are then calculated as usage per customer multiplied by customer count.

Modeling of usage per customer enables the Company to directly capture customer usage trends, housing characteristics, and efficiency trends embedded in historical data.

- Data center sales, energy, and peak demand are now being forecasted as a standalone category for the full forecast term, as opposed to just the first five years of the forecast term, and are being applied to the Company's sales, peak, and energy forecasts as an adjustment. The forecast utilizes a Company-prepared internal data center forecast through 2048.

- The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load.

Figure 4.1.2.1: 2023 Company Load Forecast

Year	DOM LSE Summer Peak Forecast (NCP) (MW)	DOM LSE Energy Forecast (GWh)
2023	17,730	95,423
2024	18,010	98,589
2025	18,157	99,262
2026	18,828	104,669
2027	19,173	107,384
2028	19,597	110,829
2029	20,021	114,070
2030	20,650	118,579
2031	21,346	123,503
2032	22,153	129,998
2033	23,019	135,928
2034	23,963	143,154
2035	24,972	151,046
2036	26,111	159,909
2037	27,220	168,151
2038	28,483	177,740
2039	29,629	186,513
2040	30,541	194,620
2041	31,361	199,934
2042	31,953	204,088
2043	32,230	206,250
2044	32,594	209,102
2045	32,821	210,586
2046	33,141	212,733
2047	33,509	214,902
2048	33,786	217,747

The following paragraphs describe the Company's internal load forecasting process.

<u>Methodology</u>

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 Models"). Both models were estimated over a rolling 15-year historical period as each long-term forecast is developed.

<u>Sales Model</u>

The Sales Model incorporates separate monthly sales equations for residential, non-data center commercial, industrial, public authority, street and traffic lighting, and wholesale customer classes. The sales equation comprises total sales for all customer classes except for residential where a use per customer forecast is developed and is then multiplied by a customer count forecast. 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 Models.

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 based on 2022 EIA surveys.

<u>Peak and Energy Model</u>

The Company's Energy Model is derived from the sales model using a regression model utilizing a historical relationship between monthly sales and monthly energy.

The Company's Peak Model is comprised of 24 separate equations, one for each hour of the day, with adjusted Company loads as the dependent variable. Prior to estimating the Peak Model equations, historical hourly loads are adjusted by subtracting data center load and adding back historical distributed solar generation and retail choice load. This adjustment is performed in order to ascertain the true load rather than a load that is masked by these factors. The Company's practice is to account for distributed solar and load management programs as supply resources, not as a load modifier.

The Peak Model equations include 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 Model also employs indicator variables to capture monthly, day of week, time of day, holiday, and other seasonal effects, as well as unusual events such as hurricanes that produce widespread outages. Once the peak forecasts are derived, the data center forecast is added back as well as adjustments for distributed solar, retail choice, incremental DSM load, and incremental EV load.

Electric Vehicle Forecast

The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load. Like data centers, a separate EV forecast is developed, and the corresponding incremental sales are added to the appropriate residential or commercial sales forecast as a model post-processing adjustment. The EV forecast was developed by Guidehouse, Inc. Figures 4.1.2.2 and 4.1.2.3 reflect the EV peak and energy forecast, respectively.

Figure 4.1.2.2 – Electric Vehicle Peak Demand Forecast (MW)

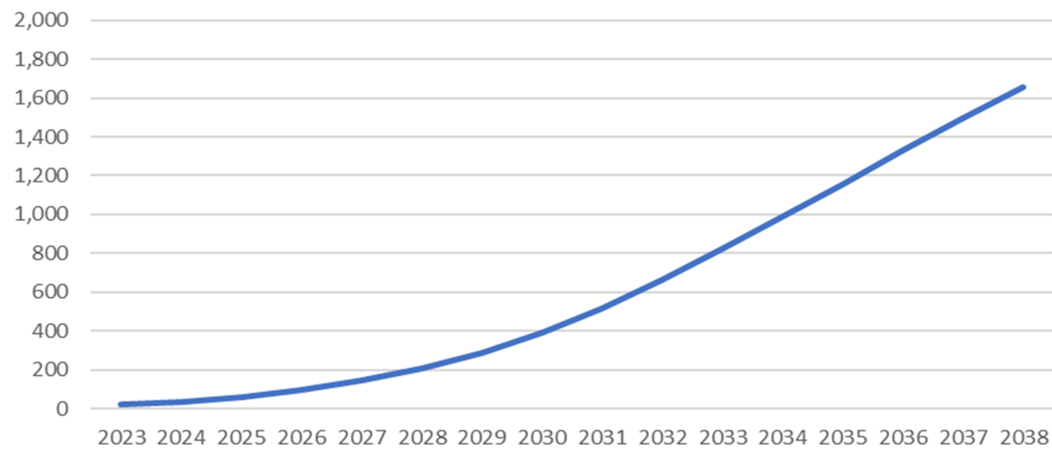
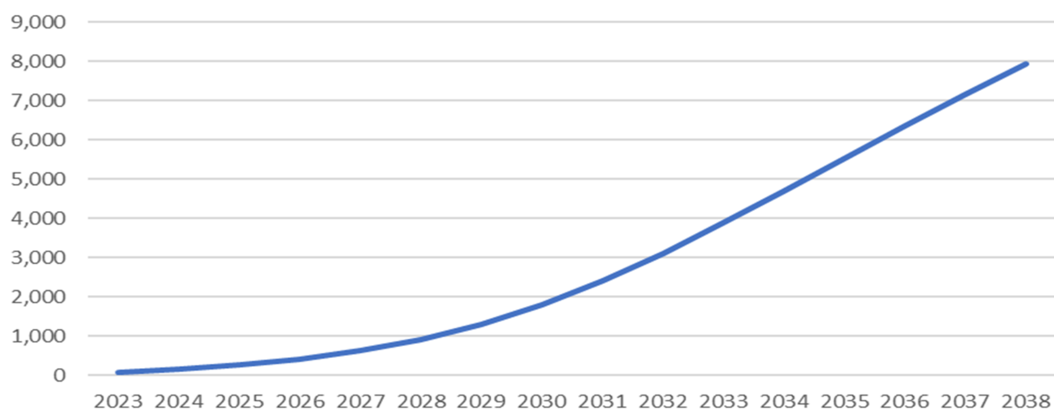


Figure 4.1.2.3 – Electric Vehicle Energy Forecast (GWh)



Economic and Demographic Assumptions

The economic and demographic assumptions that were used in the Company Load Forecast models were supplied by Moody's Analytics ("Moody's"), prepared in October 2022, and are included as Appendix 4M. Figure 4.1.2.4 summarizes the economic variables used to develop the Company's sales forecast.

Figure 4.1.2.4 - Major Assumptions for the Sales and Peak and Energy Models

	2023	2028	Compound Annual Growth Rate (%) 2023 - 2028
Demographic:			
Customers (000)			
Residential	2,468	2,631	1.3%
Commercial	253	265	0.9%
Population (000)	8,708	8,878	0.4%
Economic:			
Employment (000)			
State & Local Government[1]	534	557	0.8%
Manufacturing	238	236	-0.2%
Government[2]	722	745	0.6%
Income ($)			
Per Capita Real Disposable	47,953	53,591	2.2%
Price Index			
Consumer Price (1982-84=100)	304	339	2.2%
VA Gross State Product (GSP)	513	585	2.7%

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

Explanatory Variable Comparison

The Company relies on Virginia economic explanatory variable forecasts supplied by third parties in the development of its load forecast. The supplier of these explanatory variable forecasts for the 2023 Company Load Forecast was Moody's; PJM also used explanatory variables from Moody's in the development of its 2023 Load Forecast.

Net Metering Forecast

The net metering forecast process is based on the three-parameter Bass Diffusion Model ("BDM"). The BDM is fitted to actual net metering customer data to determine the three parameters of the BDM, which are the coefficient of innovation, the coefficient of imitation, and the ultimate market potential. The BDM model then determines the net metering customer forecast, which is then translated into energy and peak using historical data.

Wholesale Power Sales

Appendix 4K provides a list of the wholesale power sales contracts with parties to whom the Company has committed to providing full requirement wholesale power sales that are included in the Company Load Forecast.

Results

The results of the Company's forecast are represented in Figure 4.1.2.1. DOM LSE is forecasted to be a summer-peaking system. The all-time summer unrestricted peak demand for the DOM Zone is 21,156 MW and was set in August 2022. The corresponding DOM LSE peak value was

17,131 MW. However, during the recent winter period of 2022/2023, a significant DOM LSE unrestricted peak was set at 17,813 MW. Nevertheless, consistent with the 2023 PJM Forecast for the DOM Zone, the Company forecasts DOM LSE to be summer peaking.

DOM LSE peak and energy requirements are both estimated to grow annually at an approximate CAGR of 3.2% and 4.2%, respectively, throughout the Planning Period.

4.1.3 Energy Efficiency Adjustment

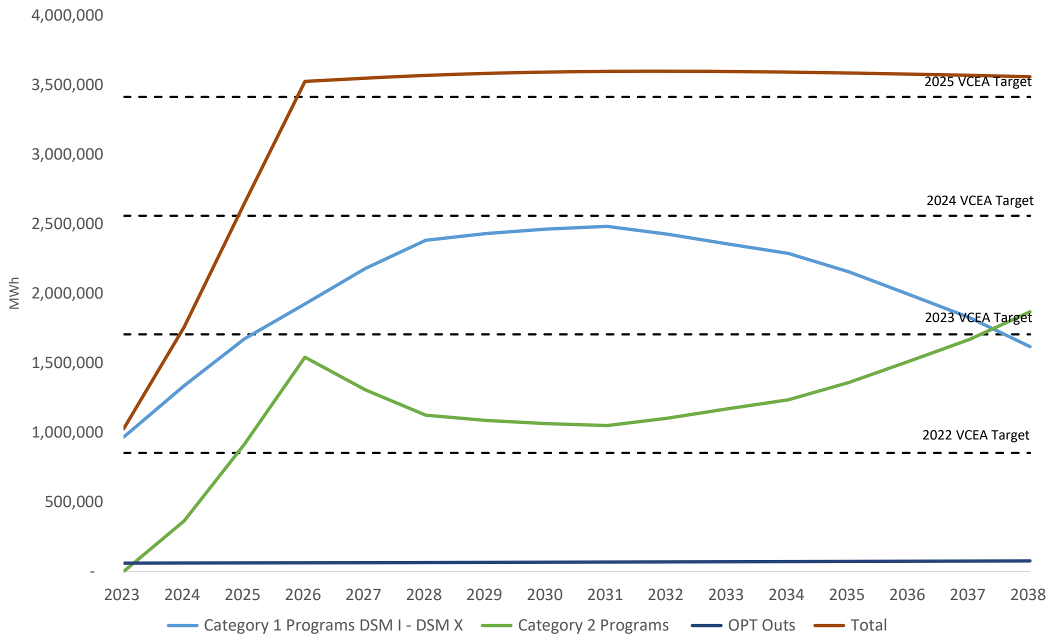
The load forecasts in this 2023 Plan include a downward post-model adjustment for energy efficiency ("EE"). The EE adjustment to the forecasts can be broken down into two distinct categories. The first category ("Category 1 Programs") consists of previously approved EE programs that remain effective (*i.e.*, that are still producing savings), along with programs that were approved by the SCC in Case No. PUR-2021-00247. The second category ("Category 2 Programs" or "generic" EE) represents unidentified EE programs and measures designed to meet legislative directives. Specifically, the generic EE is designed to meet (i) the energy savings targets in the VCEA for 2022 through 2025; (ii) a 5% energy savings target for 2026 and beyond; (iii) the GTSA requirement to propose $870 million in EE programs by 2028; and (iv) at least 15% of EE costs allocated to programs designed to benefit low-income, elderly, or disabled individuals or veterans.

Alternative Plan A is only adjusted for Category 1 Programs. Alternative Plans B through E include the additional adjustment for the Category 2 Program. The Company used the same methodology from the 2022 Update to estimate the Category 2 Program in this 2023 Plan. This methodology uses actual historic costs and savings from the Company's EE programs to determine an average dollar per kWh ("$/kWh") saved price for low-income targeted programs and non-low-income programs and then calculates the estimated projected costs to meet the VCEA energy savings targets at the prescribed levels.

This approach to generic EE is a theoretical assumption used for modeling purposes only. The actual costs and benefits of future EE will be dependent upon many factors, including the ability of future vendors to deliver program savings at the fixed price, customer participation, and the effectiveness of the program to be administered at that price. The Company assumed that the energy efficiency savings target remains constant at 5% in 2026 and beyond based on current projections of the ability of energy efficiency programs to meet these targets, as discussed further in the Company's pending DSM proceeding in Case No. PUR-2022-00210 and based on limitations to the level of energy efficiency savings that can be cost-effectively achieved. That said, the Company has provided sensitivities on Alternative Plan B under different load forecasts to show the effect if the load forecast were to vary for any number of reasons; see Section 2.6, ***Sensitivity Analyses***.

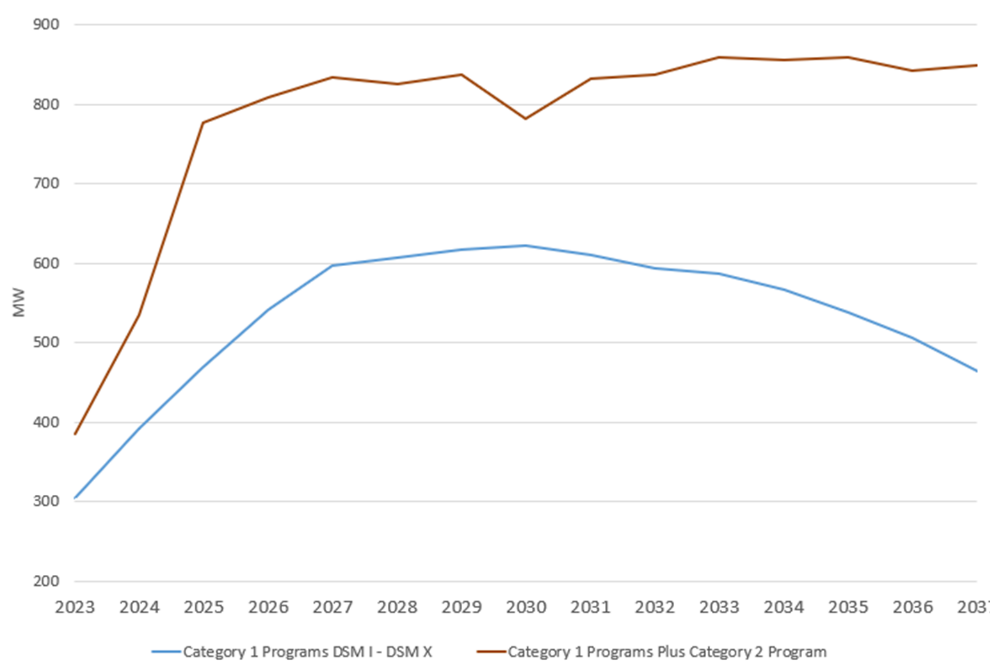
Figures 4.1.3.1 and 4.1.3.2 identify the EE energy and capacity adjustments to the load forecasts used in this 2023 Plan, respectively. Opt-out energy reductions reflected in Figure 4.1.3.1 refers to large general service customers having more than one MW of demand from a single site who have implemented energy efficiency measures at their own expense and have notified the utility and the SCC's Division of Public Utility Regulation of their non-participation in the energy efficiency riders.

Figure 4.1.3.1 – EE Energy Forecast Adjustment



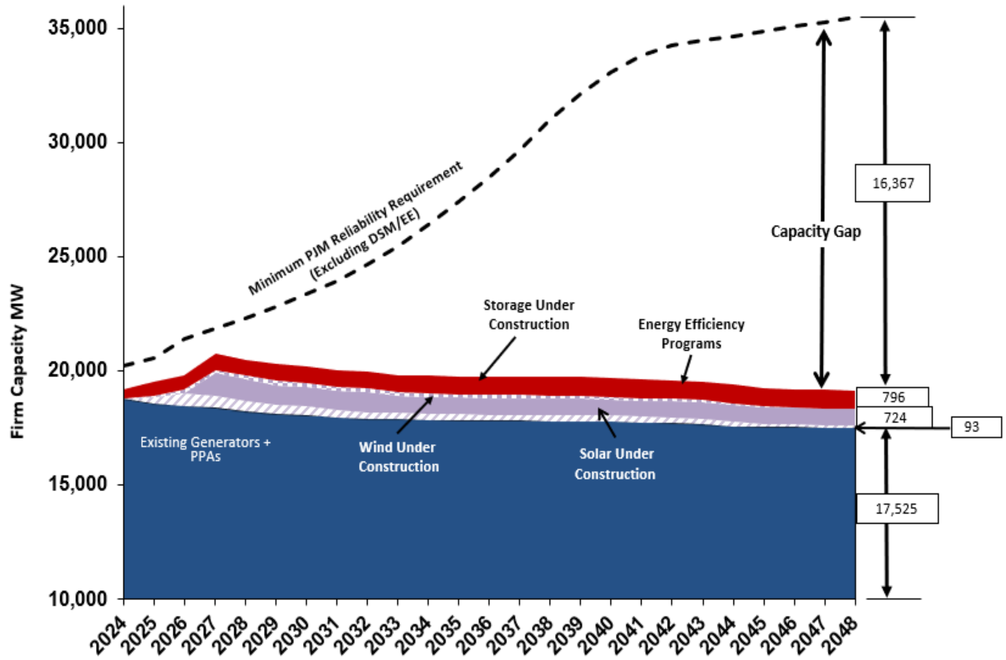
Note: All values shown are at the customer meter and do not include line losses.

Figure 4.1.3.2 – EE Coincident Summer Peak Demand Forecast Adjustment



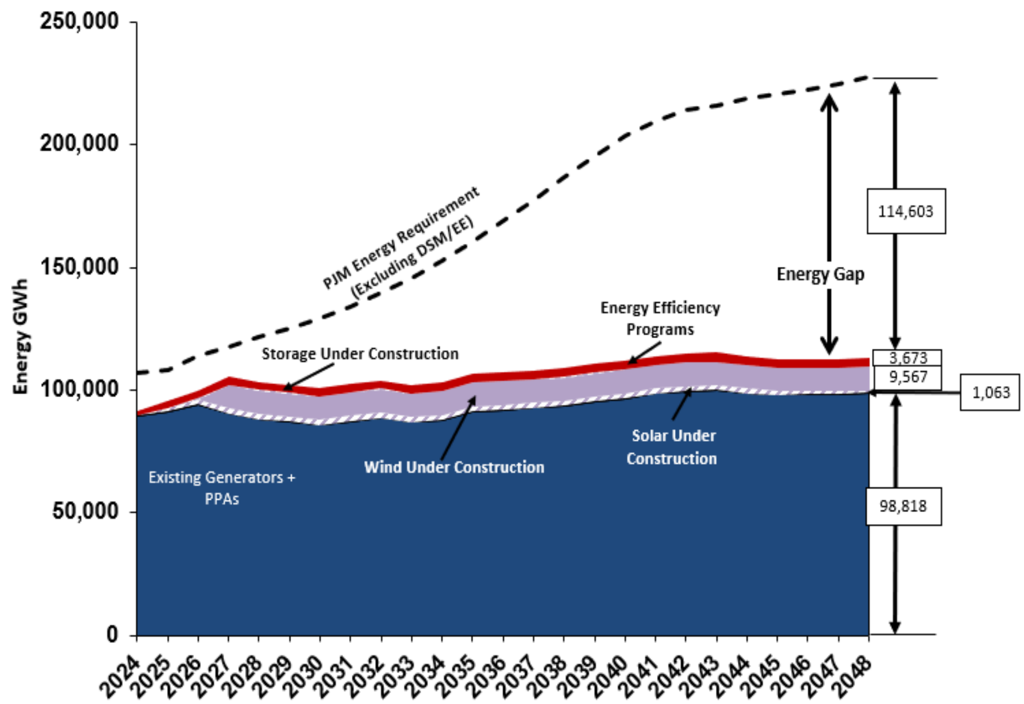
Figures 4.1.3.3 and 4.1.3.4 show the Company's current capacity and energy position with DSM modeled as a supply-side resource using unit retirement assumptions for Alternative Plan B.

Figure 4.1.3.3 - Current Company Plan B Summer Capacity Position (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency.

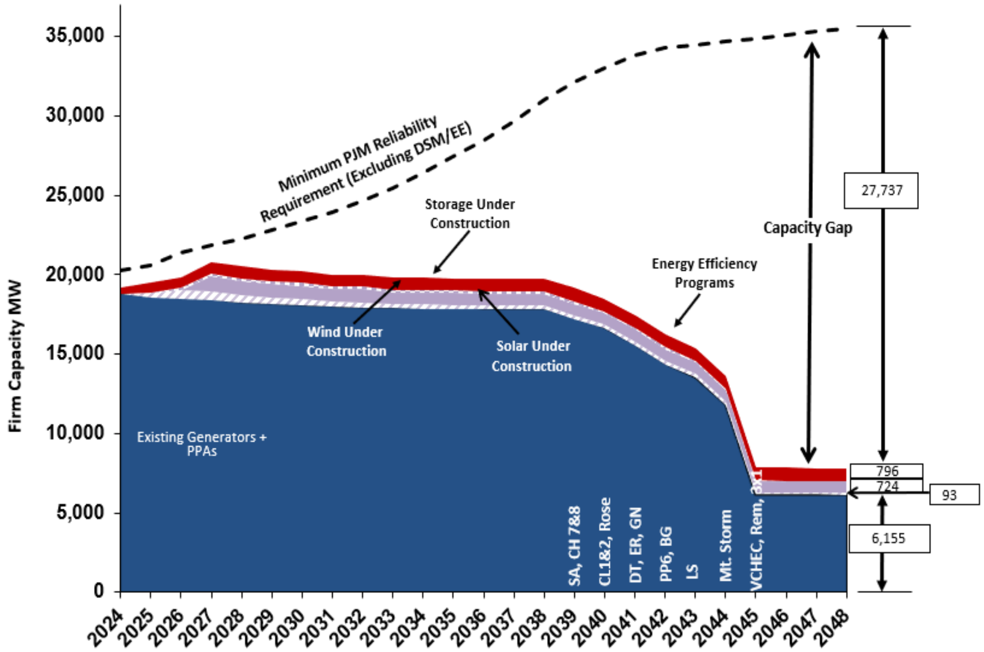
Figure 4.1.3.4 - Current Company Plan B Energy Position (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency.

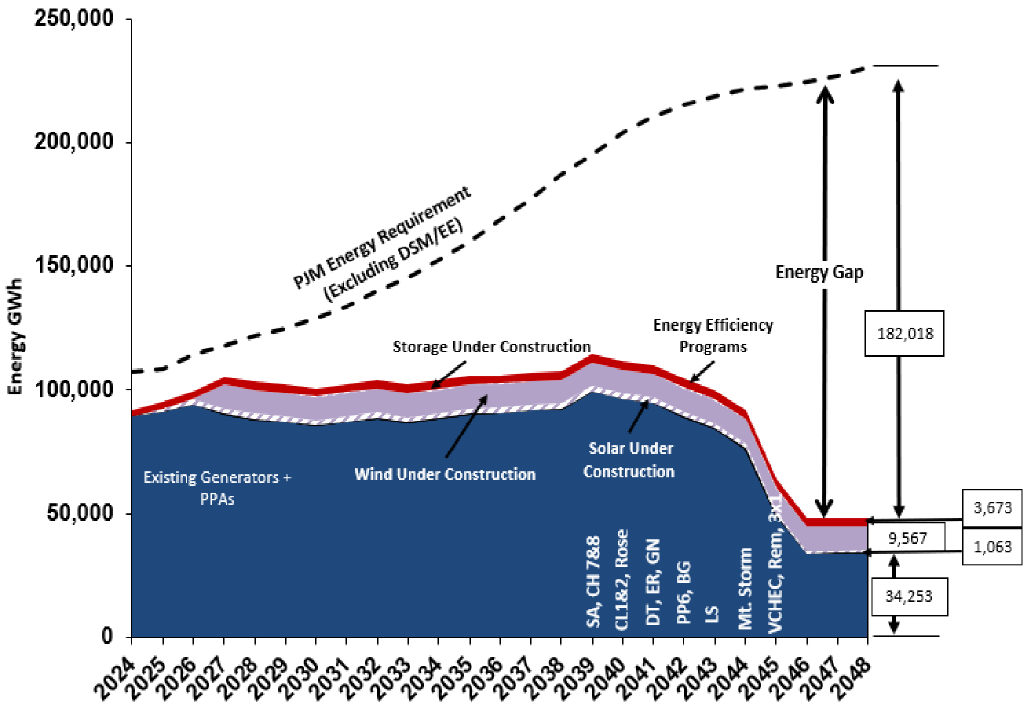
Figures 4.1.3.5 and 4.1.3.6 show the Company's current capacity and energy position with DSM modeled as a supply-side resource using unit retirement assumptions for Alternative Plan B.

Figure 4.1.3.5 - Current Company Plan D Summer Capacity Position (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency; "SA" = South Anna; "CH7&8" = Chesterfield Units 7&8 (gas); "CL1&2" = Clover Units 1 & 2 (coal); "Rose"= Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas); "3x1"= Greensville, Brunswick and Warren (gas).

Figure 4.1.3.6 - Current Company Plan D Energy Position (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency; "SA" = South Anna; "CH7&8" = Chesterfield Units 7&8 (gas); "CL1&2" = Clover Units 1 & 2 (coal); "Rose"= Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas); "3x1"= Greensville, Brunswick and Warren (gas).

4.1.4 Retail Choice Adjustment

The load forecasts in this 2023 Plan include a downward adjustment for customers within the Company's service territory who have chosen to purchase energy and capacity from third-party retail electric suppliers under Va. Code § 56-577 ("Choice Customers"). To develop this forecast the Company first identified the group of current Choice Customers. The Company then determined the annual energy for this set of customers over 2022. Finally, the Company shaped the total energy into hourly intervals using historic Choice Customer interval data.

The summation of each customer's average annual energy and capacity use then formed the starting point for the Choice Customer forecast. The Va. Code §56-577 A 3 customers, whose most recent period demand exceeded five MWs, are also required to provide the Company a 5-year written notice to return to Company service. The Company, to date, has not received such written notice, and has not made any assumptions regarding customers returning to purchase energy and capacity service from the Company. Figure 4.1.4.1 identifies the Choice Customer peak demand and energy forecast adjustment in this 2023 Plan.

Figure 4.1.4.1 – Retail Choice Adjustment

Estimated Retail Choice Sales (MWh)	Estimated Retail Choice Coincident Peak (MW)
5,109,922	820

4.1.5 Data Center Forecast

The Company serves the largest data center market in the world, located in 30 square miles of Loudoun County. There are data centers located in other areas of Virginia, but roughly 80% of the industry is located in Loudoun County. To put this in perspective, the aggregate of the next six largest data center markets in the U.S. is not as big as Loudoun County's market. The data center industry in Virginia achieved a peak metered load of almost 2.8 GW in 2022. This load is roughly 1.5 times the capacity of the Company's North Anna nuclear facility.

Growth Prospects

The data center industry is one of the fastest growing industries worldwide. In the Company's service territory, the industry has grown on average 0.5 GW a year in the last three years. Since 2019, the Company has connected 75 data centers with an eventual capacity of 3 GW. These data centers will ramp up to this capacity over time, so the Company expects this growth to materialize over the next 3 to 5 years. The big drivers of current and future growth include: migration to the cloud as companies outsource information technology functions, smartphone technology and apps, 5G technology, digitization of data, and artificial intelligence.

Types of Data Centers

The Company uses the following segments to describe, track, and forecast the industry:

1. **Cloud** – operating system in the sky (examples: Amazon, Microsoft, Google)
   - Largest segment of the Company's market
   - Cloud providers own servers
2. **Colocation** – "hotel" for other companies (example: Digital Realty)
   - Largest number of companies in the Company's service territory
   - Colocation providers do not own servers
3. **Enterprise** – dedicated facility (examples: Meta, banks)
   - Small number of players
4. **Fiber Interconnection Facility** – routers of the network
   - Small number of players and small size
5. **Bitcoin Miner** – dedicated to cryptocurrency
   - No bitcoin operators in the Company's service territory

Industry Consultant Reports

Several consultant companies publish periodic reports on the data center industry. These reputable companies report only on the colocation segment because the big cloud providers not only build their own facilities, but they also lease the most space from the colocation providers. However, the cloud providers do not publish data on their own facilities. Therefore, the industry reports only include data published in aggregate for the colocation industry; a cloud provider's lease in a colocation facility will be in the industry report. Extrapolating this to the Company's data center market, these industry reports capture less than half of the data center business.

Forecasting Methodology

The Company has been tracking data and preparing forecasts for a long period of time and has developed a very robust forecast methodology. Figure 4.1.5.1 compares the Company's forecast to actual data center demand for 2020-2022.

Figure 4.1.5.1 – Data Center Industry Peak Billed Demand in MW
Company Service Territory

Forecast Year	Forecast and Results		Variance	% of Variance
	Forecast	Actual	Over/(Under)	To Actual
2020	1,559	1,808	249	14%
2021	2,179	2,302	123	5%
2022*	2,848	2,767	(81)	-3%

* 2022 was the year of the transmission capacity constraint.

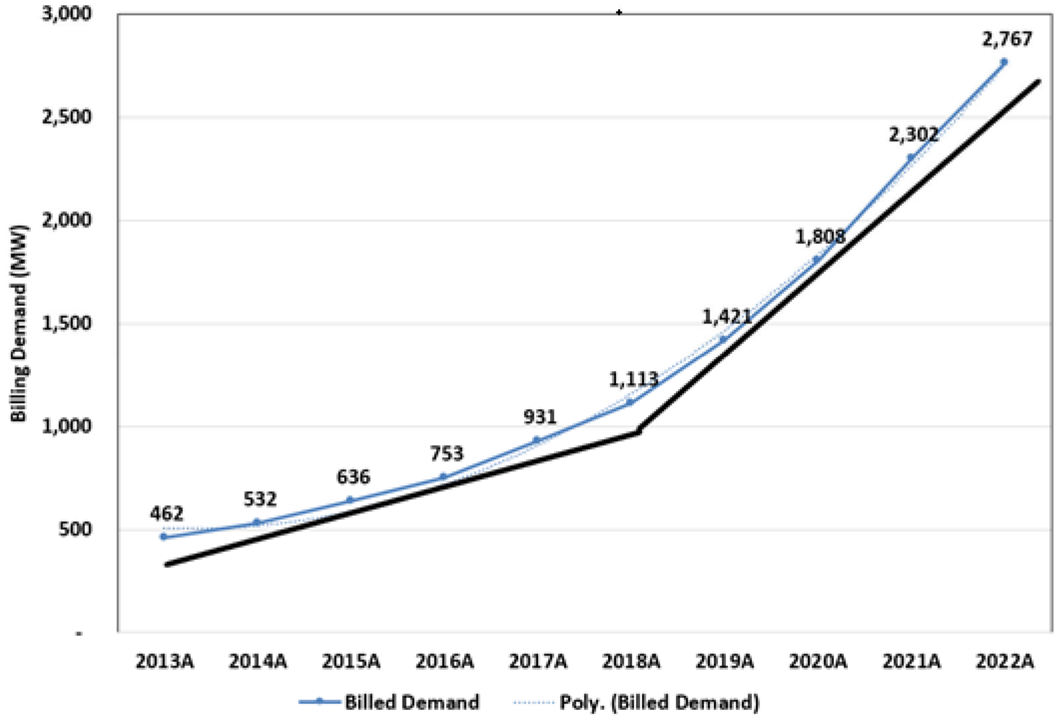
The Company models industry demand growth using the following method:

- Segments the modeling using the eight largest or fastest growing customers and a ninth model consisting of all remaining customers combined into one segment – nine models in total
- Statistically models sales in MWh including lost retail choice sales
- Statistically models demand (MW) using three different approaches
    - Approach 1: linear regression of demand
    - Approach 2: polynomial regression of demand
    - Approach 3: linear regression of sales to demand
- One of these three approaches is selected for each of the nine customer segments based on customer provided intelligence
- Estimate future retail choice conversions (lost MWh sales)
- Develop high, medium, and low demand scenarios
- In total, there are 27 models used to develop the forecast

Historical Growth in Billed Demand

Figure 4.1.5.2 highlights the growth of demand (MW) for the data center industry in the Company's service territory. Note the change in growth that occurred in 2019. Industry growth was relatively flat until 2019 when it increased substantially. The dark black lines on the growth illustrate this change. The dotted line is a polynomial trend line.

Figure 4.1.5.2 – Data Center Historical Growth of Demand in Company Service Territory



Each year, the Company prepares a 15-year forecast of data center load growth. This forecast is consistent with the Company load forecast and is also provided to PJM as requested. Figures 4.1.5.3 and 4.1.5.4 reflect the LSE data center peak and energy forecast, respectively, incorporated into this 2023 Plan.

Figure 4.1.5.3 – DOM LSE Data Center Peak Demand Forecast (MW) (Excludes Retail Choice)

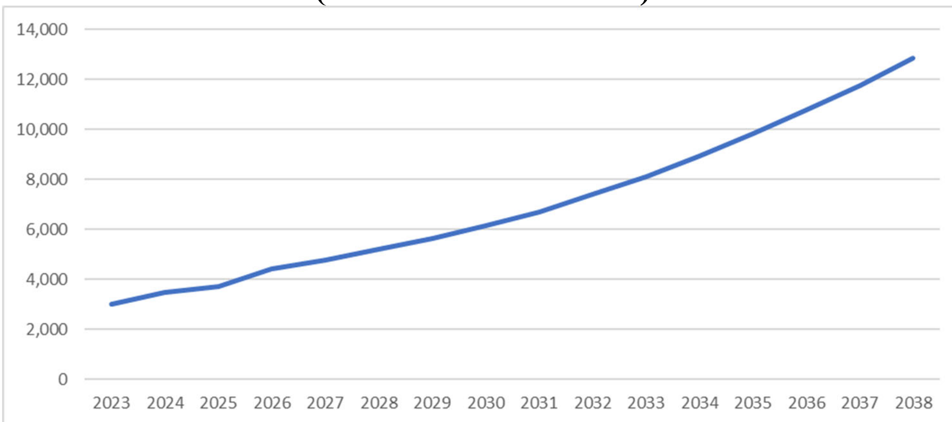
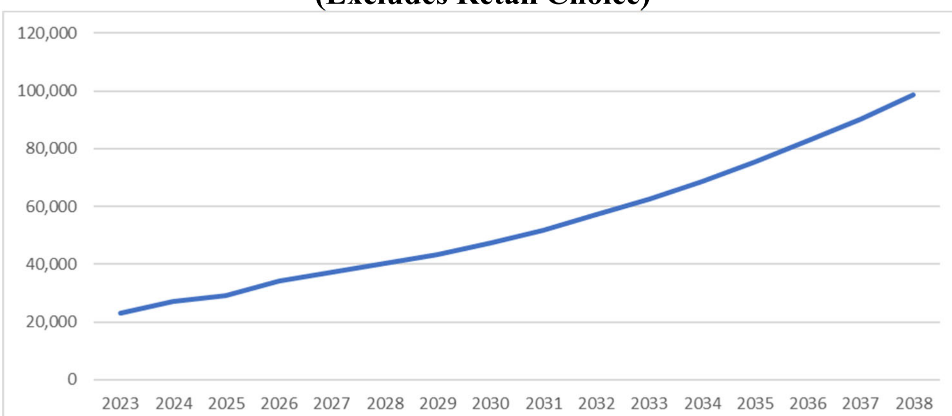


Figure 4.1.5.4 – DOM LSE Data Center Energy Forecast (GWh) (Excludes Retail Choice)



4.2 Capacity Market Assumptions

The Company participates in the PJM capacity planning process to ensure supply of capacity resources for its customer load. As a member of PJM, the Company has the option to buy capacity in order to satisfy the mandated reliability requirements either (i) through the reliability pricing model ("RPM") forward capacity market or (ii) through the fixed resource requirement ("FRR") alternative. PJM's planning years (referred to as "delivery years" for RPM) run from June 1 to May 31. The Company has satisfied its capacity obligation ~~through the RPM auction~~in the capacity market through May 31, 2025.

4.2.1 Short-Term Capacity Planning

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to purchase sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone using its annual load forecast and reserve margin guidelines as inputs. PJM then conducts a capacity auction process for meeting these input requirements up to three years into the future. This auction process includes the base RPM auction as well as subsequent incremental auctions that are held to allow market sellers and PJM to adjust positions for changes such as construction delays or outage assumptions. This auction process determines the clearing reserve margin and the capacity price for each zone for the delivery year that is three years in the future.

PJM had the 2023/2024 base residual auction ("BRA") in June 2022 and the 2024/2025 BRA in December 2022. The 2025/2026 BRA is currently scheduled for June 2023, the 2026/2027 BRA is scheduled for November 2023, and the 2027/2028 BRA is scheduled for May 2024. PJM has proposed delaying the next capacity auction until June 2024, as it attempts to fast-track reliability reforms to the capacity market design. If approved by FERC, subsequent auctions would be held every six months.

Currently, the Company offers its capacity resources, including owned and contracted generation, into its FRR Plan as a generation provider. As a LSE, the Company is obligated to provide sufficient generation to cover its load obligation. The load obligation is calculated using PJM's most current load forecast and planning parameters such as equivalent forced outage rate demand ("EFORd") and reserve margin requirements.

The Company currently satisfies its capacity obligation through the FRR alternative. This alternative allows the Company to self-supply its capacity obligation. Importantly for modeling purposes, however, the modeling is indifferent to whether the Company satisfies its capacity obligation through the RPM auction or through the FRR alternative. Operating under the FRR alternative, the Company would self-supply its capacity obligation. Instead of collecting a capacity revenue stream for generating resources, the Company assumes generating resources would obtain capacity benefit by *avoiding* capacity market purchases. For modeling purposes, the Company would continue to use capacity market forecasts and assume generating resources collect capacity benefits by avoiding capacity purchases under FRR. Further, the modeling is indifferent to whether the Company operates under the FRR alternative because the Company models the forecasted reserve margin at the minimum reserve margin, which is also the obligation under FRR.

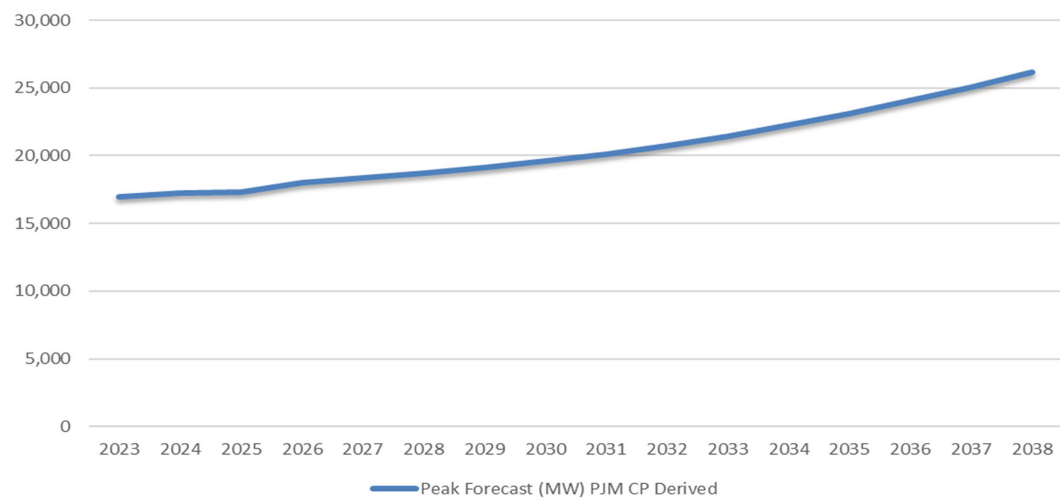
4.2.2 Long-Term Capacity Planning – Reserve Requirements

The Company uses PJM's reserve margin guidelines 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 as a loss of load expectation equivalent to one day of outage in ten years. To satisfy the NERC and Reliability First Corporation Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment, and Documentation, PJM's 2022 Reserve Requirement Study recommended using an installed reserve margin of 14.9% for delivery year 2023/2024, 14.8% for 2024/2025, 14.7% for 2025/2026, and 14.7% for 2026/2027.

PJM develops reserve margin estimates for planning (delivery) years (June to May) rather than calendar years. Because PJM is a summer peaking entity, 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 period. For example, the Company uses PJM's 2023/2024 delivery year assumptions for the 2023 calendar year in this 2023 Plan because it represents the expected peak load during the summer of 2023.

The Company makes one assumption when applying the PJM reserve margin to the Company's modeling efforts. Since PJM uses a shorter planning period than the Company (*i.e.*, ten years for PJM rather than 15 years for the Company), the Company uses the most recent PJM Reserve Requirements Study and assumes the reserve margin value for delivery year 2023 would continue throughout the Study Period. Figure 4.2.2.1 shows the adjusted load forecast used in the modeling of Alternative Plans A through E.

Figure 4.2.2.1 – PJM Derived Coincident Peak Load Forecast for DOM LSE



All Alternative Plans were optimized to meet the PJM coincident summer peak load forecast as discussed in Section 4.1.1, ***PJM Derived Load Forecast***, which is labeled as "Minimum PJM Reliability Requirement (Net of DSM/EE)" in Figure 2.1.1, as well as the capacity figures in Appendix 2A.

Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions, revisions to the PJM RPM rules, and annual updates to load and reserve requirements. Appendix 4H provides a summary of PJM's summer and winter peak load and energy forecast, while Appendix 4I provides a summary of projected PJM reserve margins for summer peak demand.

4.3 Capacity Value Assumptions

Since the fall of 2018, PJM has been developing a probabilistic analysis aimed at valuing the capacity value of renewable energy resources. This approach utilizes a concept called effective load carrying capability ("ELCC"). As defined by PJM, ELCC is a measure of the additional load that a particular generator of interest can supply without a change in reliability. ELCC can also be defined as the equivalent MW of a traditional generator that results in the same reliability outcome that a particular generator of interest (such as an intermittent generator) can provide. The metric of reliability used by PJM is loss-of-load expectation, a probabilistic metric that is driven by the timing of high loss-of-load probability hours. Therefore, PJM states that a resource that contributes a significant level of capacity during high-risk hours will have a higher capacity value (*i.e.*, a higher ELCC) than a resource that delivers the same capacity only during low-risk hours. "High-risk hours" are those hours during which PJM expects the peak demand to occur.

For the purposes of the 2023 Plan, the Company utilized the December 2022 PJM ELCC study to estimate the capacity value of solar, wind, and storage resources, which is the most recently available guidance from PJM. This approach indicated the capacity value of tracking solar is currently 55%, decreasing over time as solar saturation grows. For offshore wind, the capacity value is currently 43%, and decreases over time as offshore wind saturation grows. This is an increase from the value of 40% published in the December 2021 PJM ELCC study. For onshore wind, the class rating is 18%. For energy storage, the starting capacity value is 82% for four-hour systems, and increases after 2026.

PJM currently performs its ELCC calculations at the hourly or daily level. PJM publishes ELCC values for these resource types for a ten-year period through 2032; beyond 2032, the Company used projected ELCC values provided by ICF for the remainder of the Study Period.

On January 25, 2023, PJM stakeholders approved manual and governing document changes for a solution package that addresses the CIRs for ELCC Resources Issue Charge. CIRs are the right to input generation as a capacity resource into the transmission system at the point of interconnection where the facility connects to the PJM transmission system. The new process will begin to apply CIRs in the ELCC studies and performance adjustment calculations by capping the hourly wind and solar outputs at the CIR level starting with the 2025/2026 BRA and may result in an immediate capacity value reduction for wind and solar. These document changes were approved by the FERC in April 2023, and PJM will include the new modeling assumptions in future ELCC studies. For this reason, the Company has not incorporated any assumptions related to potential future changes into the modeling completed for this 2023 Plan.

4.3.1 Capacity Price Forecasting Methodology

In most wholesale electricity markets, electric power generators are paid for providing:

- Energy: the actual electricity consumed by customers;
- Capacity: standing ready to provide a specified amount of electric energy; and
- Ancillary services: a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves.

The purpose of a mandatory capacity market is to encourage new investments where they are most needed on the grid. PJM's capacity market (*i.e.*, the RPM), ensures long-term grid reliability by procuring the appropriate amount of supply- and demand-side resources needed to meet predicted peak demand in the future. In a capacity market, utilities or other electricity suppliers are required to purchase adequate resources to meet their customers' demand plus a reserve amount. Suppliers offer supply- or demand-side resources into the capacity market at a price. To the extent the supply offer clears the market, then those capacity resources are obligated to supply energy (or reduce energy in the case of demand-side resources) when dispatched or pay penalty fees.

The RPM is designed to provide financial incentives to attract and maintain sufficient capacity to meet the load demands anticipated by PJM; in concept, revenues from energy and ancillary services plus capacity payments should equal the amount necessary to attract new entry. Parallel to the actual market construct, forecasting of long-term capacity prices is based on estimating the amount of capacity revenue a generation resource requires, in addition to revenue from energy and ancillary services. The capacity revenue forecast represents the amount by which a resource's cost exceeds its forecasted wholesale electricity market revenues. The basic concept utilized in forecasting is that in order to maintain appropriate reserve levels to assure reliable electric service, generating resources will require sufficient revenue to cover expenses and, when necessary, support the required new investment. When wholesale market energy and ancillary services revenue is not sufficient, then capacity revenues are required to fill this gap.

When forecasting capacity prices over long periods, it is reasonable to assume markets will move toward equilibrium and will provide sufficient revenue to support existing resources and incent investment in new resources that require equity returns on the capital expended for development and construction of the new resource. In markets with excess capacity, existing resources generally set the capacity price. These resources require revenue to cover only operating expenses and do not include equity returns or significant going forward capital expenditures. Because of this, the capacity price tends to be lower in markets with excess capacity. However, over the long term, the market is expected to move to an equilibrium status where sufficient revenues are provided, which assures adequate resource capacity and encourages market efficiency. Note that while long-term forecasts tend toward an equilibrium pricing, it is expected that actual markets will continue to follow an up-and-down cycle that moves around equilibrium levels. Long-term forecasts for capacity focus on the equilibrium level pricing rather than attempting to estimate the cyclical movement.

4.4 Commodity Price Assumptions

The Company utilizes a single source—ICF—to provide multiple scenarios for the commodity price forecasts to ensure consistency in methodologies and assumptions. The key assumptions on market structure and the use of an integrated, internally consistent fundamentals-based modeling methodology remain consistent with those utilized by ICF in prior years' commodity forecasts.

The Company performed the analyses in this 2023 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, power, emissions (*e.g.*, sulfur oxide ("SOx"), nitrogen oxide ("NOx"), RGGI), and REC prices rely on forward market prices as of February 28, 2023, 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 and Federal CO_2 prices are provided by ICF for all years forecasted within this 2023 Plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM base residual auction up to the 2024/2025 delivery year, then transitioning to the ICF capacity forecast.

In the 2023 Plan, the Company utilized four commodity forecasts:

- Base Case
- High Fuel Price

- Low Fuel Price
- Virginia in RGGI

The Company used the Base Case commodity forecast for all Alternative Plans, which assumes that Virginia exits RGGI before January 1, 2024. The remaining three commodity forecasts were used to run sensitivities, which are described in Section 2.6, ***Sensitivity Analyses***. Appendix 4N provides the annual prices (in nominal dollars) for each commodity price forecast.

As with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity prices developed for this 2023 Plan. History has shown that unforeseen events and events not contemplated five or ten years before their occurrence can result in significant changes in market fundamentals. The effects of unforeseen events should be considered when evaluating the viability of long-term planning objectives. The commodity price forecasts analyzed in the 2023 Plan present reasonably likely outcomes given the current understanding of market fundamentals, but do not present all possible outcomes.

4.4.1 Base Case Commodity Forecast

The Base Case commodity forecast was developed for the Company to address a future market environment where impacts of the supply chain and commodity price dislocations of the last 24 months are incorporated into projections, natural gas continues to be a dominant marginal source of generation in PJM over the time horizon, tax credits available to renewable and clean technologies from the IRA are incorporated, and enactment of various RPS policies occur, including the VCEA.

Figure 4.4.1.1 provides a comparison of the four commodity price forecasts in this 2023 Plan with the base commodity forecast used in the 2022 Update. See Appendix 4N for additional details of these forecasts, including fuel, allowance, power price forecasts, and the PJM RTO capacity price forecast. See Appendix 4O for delivered fuel prices and primary fuel expense from the PLEXOS model output using the Base Case commodity forecast.

Figure 4.4.1.1 – Fuel, Power, and REC Price Commodity Forecast Comparison

	2023-2037 Average Value (Nominal $)	2024-2038 Average Value (Nominal $)			
Fuel Price	2022 Fed CO_2 Case	2023 Base Case	2023 High Fuel Price	2023 Low Fuel Price	2023 VA in RGGI
Henry Hub Natural Gas ($/MMbtu)	3.90	4.25	6.48	3.62	4.25
Zone 5 Delivered Natural Gas ($/MMbtu)	3.68	3.92	6.15	3.30	3.92
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	73.60	78.54	78.84	78.54	78.54
1% No. 6 Oil ($/MMbtu)	10.95	13.33	15.37	11.88	13.33
Electric and REC Prices					
PJM-DOM On-Peak ($/MWh)	43.91	44.79	61.54	40.01	45.17
PJM-DOM Off-Peak ($/MWh)	36.34	40.64	56.02	36.24	40.87
PJM Tier 1 REC Prices ($/MWh)	13.59	15.87	7.80	20.95	15.85
VA REC Prices[1] ($/MWh)	14.89	17.14	9.06	22.25	17.12
RTO Capacity Prices ($/kW-yr)	51.42	58.88	53.16	59.77	58.80

Note: (1) Reflects ICF forecast data for only rather than a market blend.

4.4.2 High / Low Fuel Price and Virginia in RGGI Commodity Forecasts

The High and Low Fuel Price commodity forecasts utilize high and low natural gas supply scenarios from the EIA to create high and low cases of natural gas fuel prices, as natural gas continues to be a dominant marginal source of generation in PJM over the time horizon in the Base Case.

A change in natural gas prices affects energy prices directly. That is, as natural gas fuel prices increase, energy prices increase. The energy price affects the revenue stream available to renewable energy generators, which in turn results in a change in REC price. In other words, as energy prices increase due to higher fuel prices, REC prices generally decrease as a result of increased renewable build. Similarly, the capacity price is also directly influenced by the marginal sources of energy and is reflective of the net energy compensation requirements. In other words, as revenue available to renewable energy generators increases due to higher fuel prices, capacity prices decrease. Hence, the movement of natural gas prices will impact the resulting power market commodity prices directly and in a consistent manner across high and low scenarios.

In the Base Case and the High and Low Fuel Price commodity forecasts, the CO_2 price forecast incorporates the assumption that Virginia exits RGGI before January 1, 2024, as well as a charge on CO_2 from the U.S. power sector after 2035.

The Virginia in RGGI case is similar to the Base Case, except it assumes that Virginia remains a member of RGGI.

4.4.3 REC Price Forecasting Methodology

ICF's REC price forecasts reflect a weighted average price comprised of multiple RPS sensitivities, including business as usual (latest RPS policies at the time of the forecast), moderate, and aggressive RPS scenarios. Additionally, ICF does not assume REC banking and bases expected renewable builds on the assumption that market participants meet any stated renewable targets.

4.5 Construction Cost Assumptions

Costs to construct new resources are difficult to assess given the current volatility in equipment pricing and supply chains. The Company made assumptions for this 2023 Plan based on best available information at the time of preparation; the Company will continue to monitor construction costs and will update these assumptions in future filings as appropriate.

For this 2023 Plan, the projected solar, onshore wind, and energy storage capital costs are based on the market in Virginia using cost data from Company-developed projects through 2022. Given the currently volatile supply chain environment, and to account for continued market demand challenges, 2023 costs were then held constant through 2026. Beyond 2026, the capital cost increases or decreases for resources were based on the 2022 National Renewable Energy Laboratory ("NREL") annual technology baseline assumptions for the moderate scenario. For SMRs, the Company analyzed capital costs estimates provided by technology vendors and developed a cost estimate based on a generic SMR site in Virginia.

For solar PPA cost assumptions, a market index price was created using the weighted average first year price from conforming PPA bids in the Company's request for proposals ("RFP") for utility-scale solar, onshore wind, and energy storage resources. The market index price was held constant through 2026, and then adjusted based on the NREL moderate scenario.

4.6 Federal Tax Credit Assumptions

Under the Inflation Reduction Act, both PTCs and ITCs have a tiered credit structure that includes a base credit, an increased credit for meeting prevailing wage and apprenticeship requirements, and two additional potential 10% bonus credits if domestic content is used in the project or the facility is located in an energy community. For the modeling completed for this 2023 Plan, the Company assumes that prevailing wage requirements are met and projects that started construction before 2022 and through 2032, receive either the increased tax credit of 30% ITCs or 2.75 ¢/kWh PTCs). The Company has not assumed any bonus credits for generic new units for modeling purposes. Yet the Company is actively pursuing the development of projects in energy communities and expects that bonus tax credits will be available for specific future projects.

The Company modeled utility-scale solar, wind, and new nuclear resources to receive PTCs, and modeled distributed solar and storage resources to receive ITCs. The Company based the tax credits on expected construction timelines and conservatively assumed that units with construction starting after 2032 received no tax credits. These assumptions are for modeling purposes only. For actual projects that the Company pursues, final tax credit decisions will be made on a project-by-project basis as the projects reach commercial operations based on risks and benefits of each tax credit option as well as market conditions and available Internal Revenue Service ("IRS") guidance.

The IRA included many provisions that have the potential to benefit customers, but additional guidance from the IRS will be required for the Company to fully analyze the impact, if any, most of these provisions will have on the Company. The relevant provisions of the Inflation Reduction Act include the following:

- ***ITC and PTC Tiered Credit System.*** The IRA introduces a tiered credit system applicable for both ITCs and PTCs. The ITCs are broken into a base credit that is 6% of qualified basis. ITCs can then be increased to 30% of qualified basis if the project either (i) meets new wage and apprenticeship requirements; or (ii) satisfies the "begins construction" test prior to January 29, 2023. Similarly, the PTCs are broken into a base credit and increased credit for meeting new wage and apprenticeship requirements. The amount of PTCs then continues to be adjusted annually for inflation.

- ***Domestic Content Bonus.*** ITCs and PTCs can be further increased by 10% if domestic content is used in the project. This bonus requires that the taxpayer certify that any steel, iron, and a minimum percentage of manufactured product that are part of the facility were produced in the United States.

- ***Community-Based Bonuses.*** An additional 10% ITC or PTC increase is available if the facility is located in an energy community. An "energy community" is generally defined as a brownfield site; an area with high employment or tax revenues in the coal, oil, or gas industry and a high unemployment rate; or an area in which a coal mine or coal fire electric generation unit has been retired. For solar and wind projects less than five megawatts, additional credits may be applied for if a project is located in a low-income community or on Native American land.

- ***Transfer of Credits.*** For taxable years beginning after December 31, 2022, taxpayers may elect to transfer certain credits to an unrelated taxpayer for cash. The credit must be transferred by the due date of the tax return for the taxable year in which the credit is generated, and a credit cannot be subsequently transferred. Taxpayers may not transfer existing credit carryforwards.

- ***Normalization for Storage.*** For stand-alone storage technology with a maximum capacity greater than 500 kW, the IRA permits taxpayers to opt out of the ITC normalization requirement. The election may not be made if it is prohibited by the public utility commission or other similar body which regulates the utility.

- ***Nuclear PTC.*** For taxable years beginning after December 31, 2023, and before December 31, 2032, electricity produced and sold by an existing nuclear facility to an unrelated person is eligible for a new PTC. This PTC is subject to a gradual phase-out (potentially to $0) to the extent revenues generated by a qualifying facility exceed $25 per MWh.

- ***Alternative Minimum Tax.*** For taxable years beginning after December 31, 2022, the IRA will impose an alternative minimum tax regime on any corporation which has an average annual adjusted financial statement income for any consecutive three-year period in excess of $1 billion.

In general, the Company selects the federal tax credit option (*i.e.*, ITCs or PTCs) when a new facility is placed in service. The Company also expects the IRA to have a positive benefit for future clean energy investments.

Overall, the Company intends to take all reasonable steps to ensure that its customers receive the full benefits of the Inflation Reduction Act.

4.7 Renewable Energy-Related Assumptions

4.7.1 New Solar Resources

In Alternative Plans A, B, and C, the Company limited the model to selecting a maximum of 900 MW of utility-scale solar per year, which is based on an assumed amount of new solar generation available each year. For Plans D and E, the Company limited the model to selecting a maximum of 900 MW of utility-scale solar per year through 2038 to reflect the maximum total capacity of projects that is expected to be constructed each year due to construction constraints and local permitting. Starting in year 2039, the Company increased the limitation to 1,200 MW per year. Meeting this higher build limit would require improvements in solar technology or possibly out of state solar facilities. For solar resources in Alternative Plan A, the Company allowed the model to select either Company-owned cost-of-service solar or third-party PPAs. For Alternative Plans

B through E, the Company modeled solar PPAs as 35% of the solar generation capacity placed in service over the Study Period in accordance with the Va. Code § 56-585.5.

For all Alternative Plans, the Company assumed a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia. Specifically, a capacity factor of 22.2% for solar tracking resources and 20.4% for solar fixed tilt resources was generally used, which represent the average capacity factors of Company-owned solar tracking and fixed-tilt facilities in Virginia for the most recent three-year period (*i.e.*, 2020, 2021, and 2022), as required by prior SCC orders. For specific resources with a design capacity factor below the applicable three-year average, the Company modeled that resource at the design capacity factor.

The Company also ran a sensitivity on Alternative Plan B using a projected design capacity factor of 25.2% for future solar resources instead of the three-year historical average capacity factor. The projected design capacity represents an average capacity factor over the life of the facility (*i.e.*, not just three years), considering degradation. The results of that sensitivity can be seen in Section 2.6, ***Sensitivity Analyses***.

4.7.2 New Offshore Wind Resources

In December 2022, the Company received approval of CVOW, which represents nearly 2,600 MW of clean energy. CVOW is thus included in all Alternative Plans in this 2023 Plan. The Company modeled CVOW using a 42% capacity factor, a 30-year life, and updated ELCC capacity values for offshore wind as discussed in Section 4.3, ***Capacity Value Assumptions***. In all Alternative Plans a second 2,600 MW tranche of offshore wind is available for selection beginning in 2033, which represents the earliest commercial operation date ("COD") for such a project. The same operational modeling assumptions were used for this second offshore wind facility. In Alternative Plans B and D, the Company forced the model to select the second tranche of offshore wind in 2033, to diversify its carbon-free generation sources and meet the Commonwealth's clean energy goals consistent with the timeframe specified in the VCEA and House Bill 2444.

4.7.3 New Onshore Wind Resources

Onshore wind was made available for selection in this 2023 Plan. Like offshore wind, onshore wind requires siting at specific locations to maximize the value for such facilities. The Company made two specific projects under development in Virginia available for selection—a 120 MW project with a net capacity factor of 36.5% and an 80 MW project with a net capacity factor of 42.4%. In addition to these two specific projects, the Company made an additional 60 MW generic onshore wind resource with a capacity factor of 39.5% available for selection once every three years beginning in 2028. While the Company is interested in cost-effective onshore wind projects, the current availability of land suitable for onshore wind construction in Virginia is, and likely will continue to be, a limiting development constraint.

4.7.4 REC-Related Assumptions

For each Alternative Plan, the Company allowed the model to select 100% of RECs for Virginia RPS Program compliance purchased from a PJM REC market through 2024 and assumed that all RECs produced by Company-owned or contracted resources located in Virginia were banked for future use. Beginning in 2025, the Company allowed the model to select 25% of RECs as purchases from a PJM REC market and 5% of RECs for RPS Program compliance as purchases from a Virginia REC market for the remainder of the Study Period. Considering the 2023 PJM Load Forecast, growing RPS Program requirements in Virginia and throughout PJM, and a constrained development environment, the Company does not believe the REC markets will support more than 30% of its RPS Program requirements after 2025. The Company took a conservative approach for modeling purposes assuming that the majority of these REC purchases would take place in a lower-priced PJM REC market. See Section 1.7, ***Virginia REC Market***, for additional discussion of the Company's rationale for these assumptions.

REC banking is not possible in PLEXOS, so all REC banking and deficiency payment adjustments are made outside of the model. To account for this, the Company incorporated into the NPVs for each Alternative Plan a credit for excess RECs modeled during banking and a charge for deficiency payments once there is a REC shortage. The Company assumed all RECs generated at Virginia-sited facilities are banked through 2024, ahead of the in-state REC requirement beginning in 2025.

Starting in 2025, RECs are provided by a combination of renewable generation and 30% market purchases. When there is an excess of RECs, the credits are banked for the next year's compliance. Due to the new increased ARB adjustment, REC banking continues until 2033 or 2034 depending on the Alternative Plan. Once there is a deficiency of RECs, customers are charged the deficiency price multiplied by the current year's deficiency volume (in MWhs). By 2039, Plans A, B, and C, have a deficiency of RECs. Plans D and E build enough renewable and zero carbon generation that no deficiency is experienced.

The Company also included its Virginia Schedule 19 PPAs with long-term REC contracts as reductions to the overall RPS Program requirement in all Alternative Plans. The Company identified four solar facilities from which the Company purchases a bundled product comprised of capacity and energy through a Schedule 19 PPA and RECs through a long-term contract. Two of these facilities were included in the behind-the-meter reductions during the PJM load forecast development process; accordingly, the Company did not model these facilities in PLEXOS. Instead, the capacity and energy of these facilities are assumed to be reflected in the 2023 PJM Load Forecast while the RECs were accounted for by reducing the annual Virginia RPS Program requirement by the amount of RECs (as measured by generation) that these units will provide annually. The other two facilities are not behind-the-meter, so were included in the PLEXOS model directly; these facilities are in the "Existing Generation" category on the capacity, energy, and REC charts shown in Section 2.1, ***Capacity, Energy, and REC Positions***.

4.7.5 Renewable Energy Interconnection and Integration Costs

The integration of intermittent renewable energy generation into the electric grid involves multiple considerations. The generator must first be physically interconnected to the electric grid, either at the transmission or distribution level. The developer of a generating facility typically pays the costs to physically interconnect the resource, including any upgrades required near the point of interconnection to assure grid stability. The Company refers to these costs in this 2023 Plan as renewable energy interconnection costs. As increasing volumes of renewable energy generation are interconnected to the grid, additional system-level upgrades must be made by the Company to address grid stability and reliability issues caused by the intermittent nature of these resources. The Company refers to the costs related to these upgrades in this 2023 Plan as renewable energy integration costs. All of these costs are incorporated in the NPV for "Total System Costs" shown in Figure 2.4.1.

In this 2023 Plan, three different categories of solar resources were available in PLEXOS: (i) Company-build solar; (ii) solar PPAs; and (iii) small-scale solar (*i.e.*, less than 3 MW). The Company assumed interconnection cost of $156/kW for Company-build solar and $965/kW for small-scale solar. The Company assumed $0 in interconnection costs for solar PPAs because the PPA price from the developer includes interconnection costs. For wind, the Company assumed the interconnection costs for offshore wind to be $553.73/kW.

In addition to interconnections costs, this 2023 Plan includes three categories of system upgrades costs based on different issues caused by the intermittent nature of renewable energy resources:

Transmission Integration Costs: These costs represent physical enhancements to the transmission system needed to resolve low voltage and thermal conditions caused by integrating significant volumes of solar generation.

Generation Re-dispatch Costs: This category represents costs resulting from real-time variability of load and generator availability compared to day-ahead forecasted load and generator availability.

Regulating Reserves Costs: This category represents ancillary payments the Company must make to resources to ensure that the system can balance intra-day or intra-hour differences in load and generation.

The sections below explain the analyses performed for each of these three categories. While the Company has refined its methods to estimate the renewable energy integration costs compared to prior Plans, more analysis is required in order to fully assess the necessary grid modifications and associated costs of integrating increasing amounts of solar generation.

<u>Transmission Integration Costs</u>

The transmission integration cost was assessed by performing a steady state power flow analysis when a total of 20 GW and 30 GW of solar generation is present on the transmission grid. The analysis was performed based off of PJM's generation interconnection queue to best reflect the interconnection locations, sizes, and behaviors of the solar developers. The resulting power flow violations results were then used to calculate the cost per kW of enhancements to the Company's transmission system.

All Alternative Plans include the addition of significantly more solar generation. Figure 4.6.3.1 shows the incremental integration costs assumed for Company-build solar as additional solar generation is added to the system.

Figure 4.6.3.1 - Total Solar Integration Costs

Solar MW	Total Cost
Up to 20,000	$103.26 per kW
20,000- 30,000	$129.34 per kW

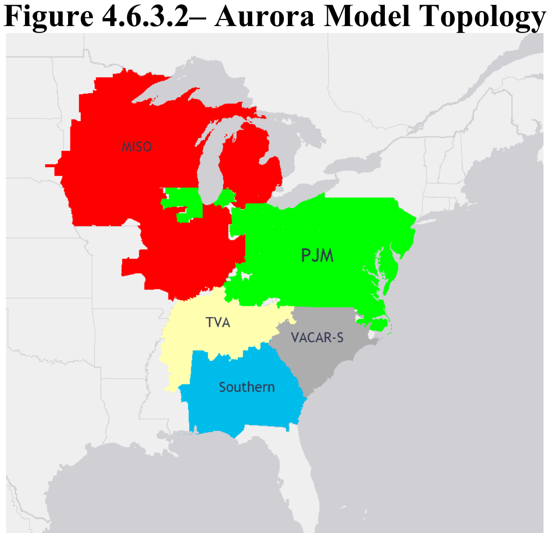
Generation Re-dispatch Costs

Re-dispatch generation costs are defined 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. 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 intermittent generation — like solar or wind — is added to the grid, additional uncertainty about re-dispatch costs is added due to factors such as 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 cost impact on generation operations at varying levels of solar, onshore wind and offshore wind penetration. To study the effects of these intermittent resources, the Company studied historic wind speed and solar irradiance data from the NREL.

To perform its generation re-dispatch costs analysis, the Company utilized the Aurora planning model with a regional simulation topology consisting of PJM Interconnection, VACAR South, Southern Company, Tennessee Valley Authority, and large sections of Midwest ISO (see map below). The results from the Aurora model captured not only the DOM Zone hourly prices interactively, but also the potential system cost impacts from intermittent resources outside the Company's service territory.

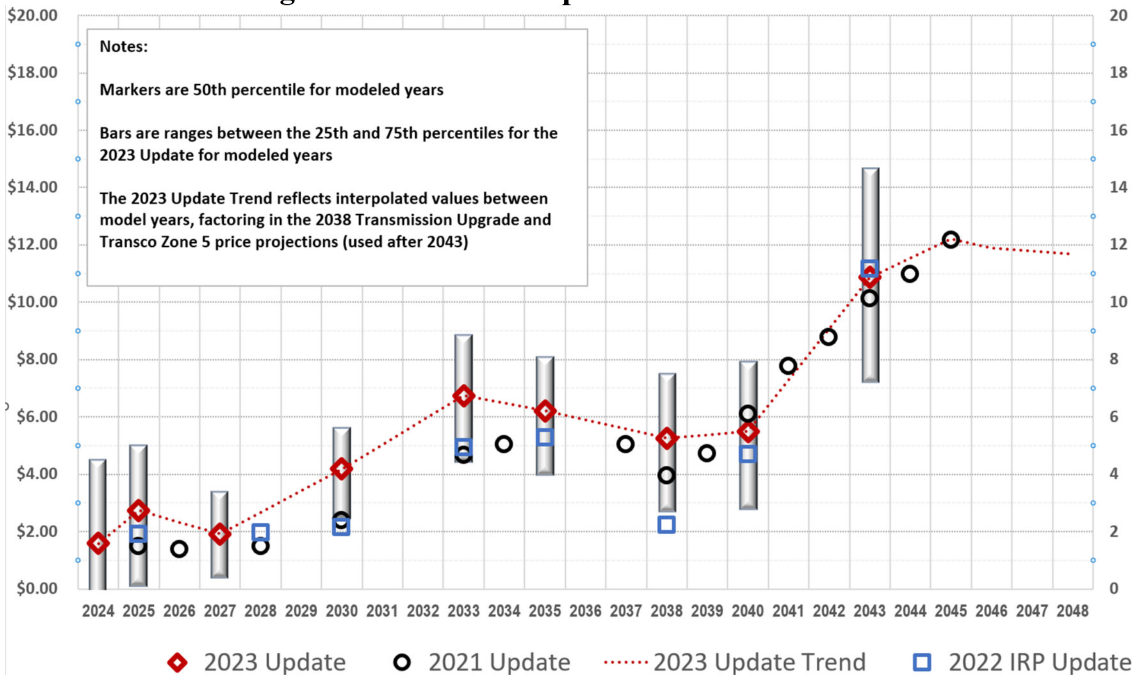
Figure 4.6.3.2– Aurora Model Topology



For each simulation year, the Company performed a base case Aurora simulation by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, the Company performed an additional 200 simulations but applying different hourly renewable profiles from the NREL historical weather patterns studies to re-optimize the system cost.

The total system cost for each simulation was compared to the base case system cost of the same year. This delta of the system cost is composed of the respective differences in fuel cost, variable operations and maintenance ("O&M") cost, emission cost, and purchase and sale costs. The re-dispatch cost is the delta of the system cost divided by the Company's expected total renewable generation.

Figure 4.6.3.3 – Re-Dispatch Cost Results



Regulating Reserve Costs

Regulating reserves are defined as additional reserves needed to balance the uncertainty of forecast errors in net load that occur during a typical power system operational day. These reserves exclude contingency reserves, which are defined as the loss of a major power system generation or transmission system asset. Within the PJM market, these regulating reserves are an ancillary service, the cost of which is charged to customers. Revenues collected for this ancillary service are paid to resources available to supply or reduce energy to correct forecast errors. Unlike contingency reserves, regulating reserves are needed to either increase or decrease generation in any given operational hour. These reserves also differ from re-dispatch costs; they are paid to the resource whether they are used or not during the operating hour. The regulating reserve costs ensure that the transmission system has adequate resources available to handle forecast uncertainty. The system pays for regulating reserves so that it has the capability to quickly re-dispatch. In contrast, the operating costs to dispatch these regulating resources (to mitigate forecast errors and stabilize the transmission system) are part of re-dispatch costs.

Historically, the level of regulating reserves was primarily driven by the uncertainty associated with load during any given operating day. The intermittent nature of solar and wind generation adds to this uncertainty. Accordingly, the levels of regulating reserves will need to increase to compensate for this added uncertainty.

A variety of resources can be used to address system uncertainty: energy storage, unscheduled CT capacity, unscheduled duct burner capacity (on scheduled combined-cycle units), intraday purchases and sales, and interruptible load.

In order to assess the increase of regulating reserves that will result from increasing volumes of solar generation, the Company utilized the Electric Power Research Institute Dynamic Assessment and Determination of Operating Reserves tool. This tool calculates operating reserves based on correlations to other variables (*e.g.*, forecasted generation, time of day) and can be used to evaluate solar, wind, and load variations separately and in combination. The reserves volume required is then reduced by the expected geographic diversity of the resources and technological diversity of these resources (wind vs. solar).

Once the MW volume of solar and wind was determined as described above, the next phase of the analysis was to determine a market price for these reserves. This was based on a historical analysis of PJM day-ahead secondary reserves and is capped by the cost of new entry of a new combustion turbine resource. The results of this analysis reflect the hourly cost of regulating reserves gradually increases from $0.67/MWh in 2024 to $14.29/MWh in 2048. This occurs because the rate that PJM is forecasted to increase the need for regulating reserves (driven by the level of renewables build) grows more quickly within PJM than the projected addition of resources that provide regulation reserves in PJM. The forecasts of resource additions are based on ICF projections in states other than Virginia. Virginia resource additions are based on the projections in this 2023 Plan for the Company; for Appalachian Power Company and other sellers of electric power in Virginia, the projections assume solar and wind resource additions according to the RPS requirements for Appalachian Power Company.

From the Company's perspective, regulating reserve costs will be incurred when the regulating costs to serve the Company's load exceed the revenue received from PJM for the Company units that supply this ancillary service.

Figure 4.6.3.4 – Net Regulating Reserves Cost of Market Purchases ($M)

Year	Plan A	Plan B	Plan C	Plan D	Plan E
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0
2028	$4	$0	$0	$0	$0
2029	$24	$0	$13	$0	$0
2030	$51	$0	$39	$0	$0
2031	$78	$0	$0	$0	$0
2032	$97	$0	$0	$0	$0
2033	$103	$110	$125	$110	$122
2034	$266	$126	$156	$126	$133
2035	$278	$101	$185	$138	$140
2036	$292	$72	$215	$149	$150
2037	$192	$46	$213	$163	$182
2038	$164	$15	$208	$174	$194
2039	$133	$22	$242	$161	$167
2040	$105	$33	$282	$137	$143
2041	$70	$39	$316	$196	$201
2042	$33	$44	$351	$168	$170
2043	$0	$54	$392	$210	$212
2044	$0	$60	$431	$178	$180
2045	$0	$65	$469	$230	$202
2046	$0	$76	$514	$251	$220
2047	$0	$82	$556	$265	$233
2048	$0	$90	$598	$269	$245

4.8 Storage-Related Assumptions

All storage developed in this 2023 Plan is assumed to be four-hour, lithium-ion batteries, though the Company is pursuing a long duration storage pilot as well. For the planning period, all plans were limited to 300 MW per year. In order to reach net zero, Alternative Plans D and E allowed 900 MW per year after 2038. In Alternative Plans B and D, the Company set constraints requiring the PLEXOS model to select 2,700 MW of energy storage by 2035, consistent with the VCEA. Third-party owned energy storage will make up 35% of the 2,700 MW. The Company plans to meet interim VCEA targets, but storage development will be more heavily weighted to the later part of the planning period, when more renewable penetration increases the value of battery storage and additional technology options are commercially available.

4.9 Gas Transportation Cost Assumptions

Natural gas is largely delivered on a just-in-time basis. Vulnerabilities in natural gas supply and transportation must be sufficiently evaluated from a planning and reliability perspective.

Mitigating strategies such as storage, peaking services, on-site fuel capability, firm natural gas supply purchases, firm pipeline transportation capacity, alternate pipelines, dual-fuel capability, access to multiple natural gas supply basins, and overall fuel diversity all help to alleviate this risk.

There are two main types of pipeline transportation service contracts: firm and interruptible. Natural gas delivered using a firm pipeline transportation service contract is available to the customer during the contract term and is not subject to a prior transportation service claim from another customer. The Company regularly uses both primary and secondary receipt and delivery flexibility inherent in its pipeline firm transportation contracts to reliably deliver fuel to its gas-fired generation fleet. While a pipeline force majeure event can interrupt primary, firm transportation service, pipeline constraints, and restrictions can limit some or all secondary receipt / delivery flexibility, beyond primary firm contractual rights. Additionally, for firm natural gas supply to be delivered reliably, sufficient supply must be scheduled in accordance with FERC-approved pipeline nomination cycles, flow rules, and then- effective pipeline constraints and restrictions.

For a firm pipeline transportation and/or storage service contract, the customer pays a monthly capacity reservation charge that recovers its share of FERC-approved pipeline fixed costs supporting the firm service. Interruptible pipeline transportation service contracts provide transportation subject to the contractual rights of firm customers and other pipeline constraints and restrictions. The Company predominantly uses firm pipeline transportation and firm storage services to fuel its natural gas-fired generation fleet but can also use interruptible pipeline transportation service depending on availability and PJM-directed need for gas-fired generation.

The Company included natural gas pipeline transportation and storage costs in its modeling. The Company predominantly uses firm pipeline transportation and storage to fuel its combined-cycle facilities. Additionally, the Company can utilize a firm pipeline transportation service not otherwise needed for its combined-cycle facilities, to fuel its CTs. When available, the Company can utilize interruptible pipeline transportation service for CTs because these peaking resources typically operate with less than 20% capacity factors and are typically equipped with on-site backup fuel. When setting capacity factor limits for new incremental CT units, the Company assumed gas availability in the spring, summer, and fall, with oil only operations in the winter when gas is most constrained.

The Company continually evaluates its generation fueling portfolio (including firm and interruptible natural gas pipeline transportation services) with fuel deliverability, flexibility, and affordability in mind. Specifically for natural gas, given the physical location of the Company's gas-fired generation fleet is in a fully subscribed pipeline corridor, pipeline constraints and associated restrictions to secondary flexibility rights are commonplace. Therefore, in the interest of generation fuel reliability, the Company requests and reviews proposals (covering various terms) for incremental firm transportation, pipeline storage, peaking services, and onsite fueling (oil or LNG). For example, given the current construction and regulatory uncertainties associated with new natural gas pipeline builds, natural gas peaking services or on-site LNG can be effective options to place specified amounts of natural gas fuel at specified locations for peak periods.

4.10 Social Cost of Carbon

The social cost of carbon is an estimate in dollars of the economic damages that result from emitting one ton of carbon into the air. For the past two years, the Company has incorporated a social cost of carbon dispatch adder in its modeling assumptions; however, given the higher federal carbon forecast assumptions received in the ICF forecast this year, the carbon adder seemed duplicative. The Company continues to believe that some federal economic incentive will be required for the country to reduce emissions and will revisit this assumption in future modeling. The Company will also continue to consider the social cost or benefit of carbon in future CPCNs as required.

4.11 Least-Cost Plan Assumptions

Alternative Plan A presents a least-cost plan using assumptions required by the SCC. Specifically, Plan A uses the 2023 PJM Load Forecast adjusted for only existing and proposed energy efficiency, consistent with prior SCC orders. It meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA; see Section 4.4, ***Commodity Price Assumptions*** and Section 5.2.3, ***Environmental Regulations***, for the Company's assumptions regarding "applicable carbon regulations." For Plan A, the Company did not force the model to select any specific resources and did not exclude any reasonable resource options. Consistent with this directive from prior orders, the Company did not exclude carbon-emitting resources as an option to reliably meet customers' energy and capacity needs. The Company also included reasonable build constraints in Plan A, including the 900 MW annual solar limit. The potential unit retirements shown in Plan A are those selected by PLEXOS without regard for other factors that the Company considers when evaluating unit retirements, as discussed further in Section 5.2.1, ***Retirements***.

4.12 PLEXOS Modeling Refinements

The Company has included several refinements to PLEXOS since the 2020 Plan to incorporate the many requirements of the VCEA, including:

- A dynamic RPS Program requirement based on forecasted customer sales;
- The ability to purchase RECs from eligible market sources to satisfy a portion of the Company's RPS Program requirements;
- An adjustment to the REC requirement to account for ARB customers, maintaining 2022 ARB certification percentages;
- Deficiency payment logic that allows the model to choose a deficiency payment for RPS Program compliance, as established by the VCEA, if economically advantageous for customers compared to other options;
- Adjustments for excess RECs that can be sold to reduce customer cost;
- Included the options to purchase RECs from a Virginia REC market based on initial forecasted price assumptions received from ICF;
- Optimized generating unit retirement logic for least-cost modeling;
- Included a declining cost curve for solar and storage unit capital costs consistent with the NREL annual technology baseline assumptions for the moderate scenario, as discussed in Section 1.6, ***Commodity Price and Cost Assumptions***;
- Modeled distributed solar and all energy storage as combination units that reflect the costs of 65% Company-owned resources to 35% PPAs;

- Re-optimized the model for the cost sensitivities presented in Figure 2.6.3, rather than locking down the base case build plan; and
- Modeled named solar units at the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia.

The Company will continue to refine its modeling as additional functionality becomes available in PLEXOS. The Company notes that REC banking remains unavailable in PLEXOS at this time.

Chapter 5: Generation – Supply-Side Resources

This chapter provides an overview of the Company's existing supply-side generation, the generation resources under construction or development, and the Company's analysis of future supply-side generation. This chapter also provides a discussion of challenges related to the development of significant volumes of solar resources.

5.1 Existing Supply-Side Generation

5.1.1 System Fleet

Figure 5.1.1.1 shows the Company's 2022 capacity resource mix by unit type.

Figure 5.1.1.1 – 2022 Capacity Resource Mix by Unit Type

Generation Resource Type	Net Summer Capacity (MW)	Percentage (%)
Coal	3,680	17.9%
Nuclear	3,348	16.2%
Natural Gas	8,392	40.7%
Pumped Storage	1,808	8.8%
Oil	1,373	6.7%
Renewable	903	4.4%
PPA-Other	179	0.9%
PPA- Hydro	5	0.0%
PPA- Solar	921	4.5%
PPA- Contracted	**1,105**	**5.4%**
Company Owned	**19,504**	**94.6%**
Company Owned and PPA Contracted	**20,609**	**100.0%**
Purchases	**0**	**0.0%**
Total	**20,609**	**100.0%**

Due to differences in 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 dispatched by PJM within PJM's larger footprint, ensuring that customers in the Company's service territory receive the economic benefit of all resources in the PJM power pool regardless of the source. PJM dispatches resources within the DOM Zone from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. Figures 5.1.1.2 and 5.1.1.3 provide the Company's 2022 actual capacity and energy mix.

Figure 5.1.1.2 – 2022 Actual Capacity Mix

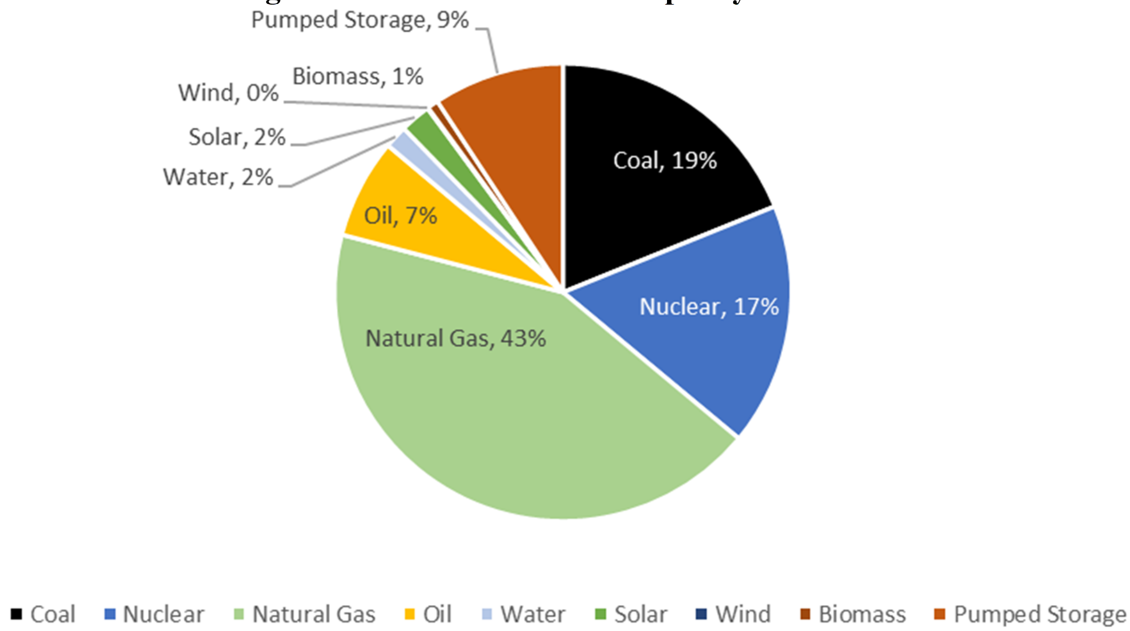
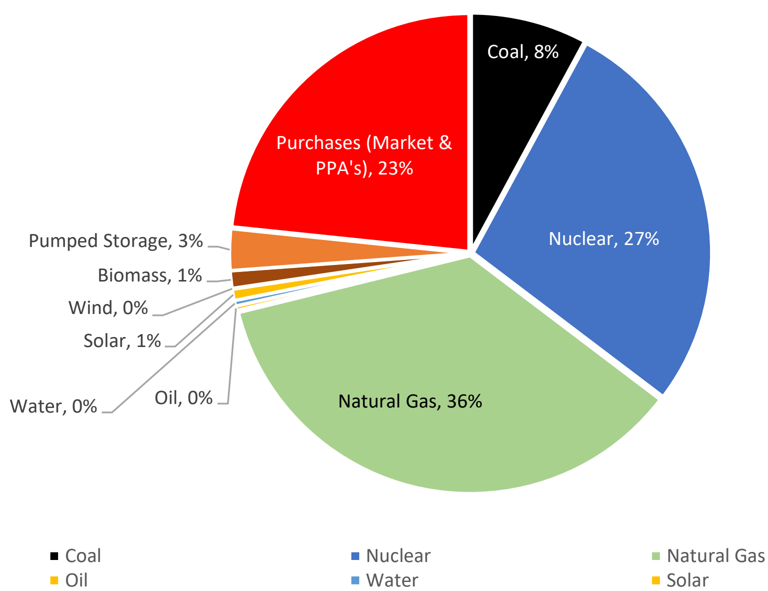


Figure 5.1.1.3 – 2022 Actual Energy Mix



Appendices 5A through 5E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Appendix 5F provides a summary of the existing capacity by fuel class. Appendices 5G and 5H provide energy generation by type and by the system output mix. Appendix 5I provides a list of all Company-build or third-party PPA solar and wind generating facilities placed in service, under construction, or under development since July 1, 2018. Appendix 5O provides a list of renewable energy resources, and

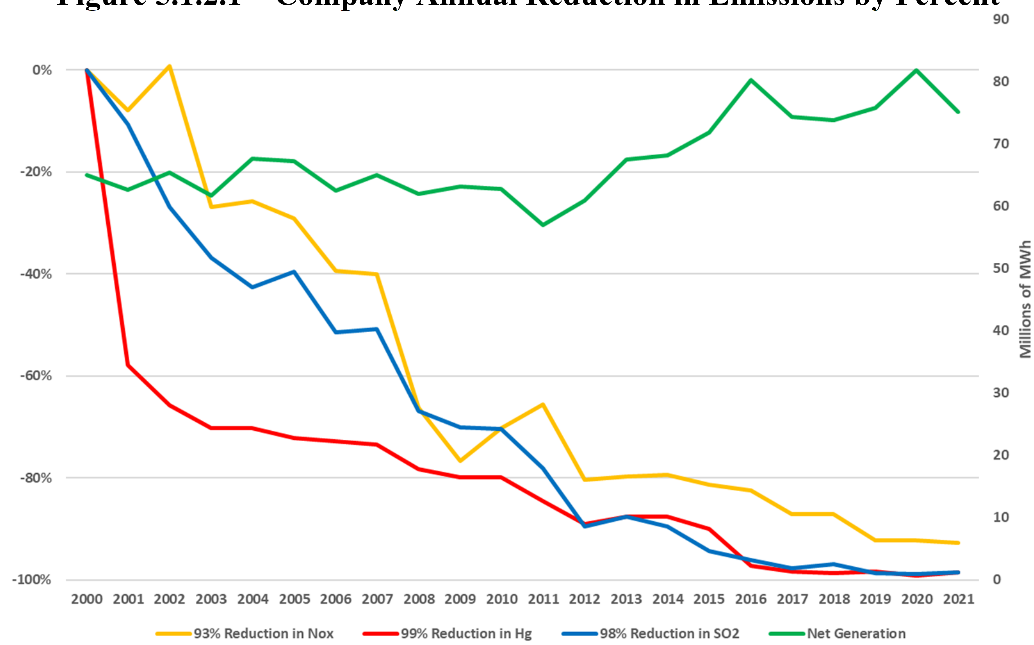
Appendix 5P provides a list of potential supply-side resources. Appendices 5Q and 5R present the Company's summer capacity position and seasonal capability, respectively. Appendix 5S provides the construction cost forecast for Alternative Plan B.

5.1.2 Company-Owned System Generation

The Company's existing system generating resources are located at multiple sites distributed throughout its service territory. This diverse fleet of 91 generation units includes 4 nuclear, 8 coal, 9 combined-cycles ("CCs"), 40 CTs, 3 biomass, 1 heavy oil, 6 pumped storage, 1 battery storage, 9 hydro, 1 offshore wind, and 9 solar with a total summer capacity of approximately 21,713 MW. For details on the Company's existing generating resources, see Appendix 5A. The Company currently owns and operates 903 MW of renewable energy resources, including solar, wind, hydroelectric, storage, and biomass, with an additional 200 MW (nameplate) under construction. The Company also owns and operates four nuclear facilities (3,349 MW), providing significant zero-carbon generation for its customers.

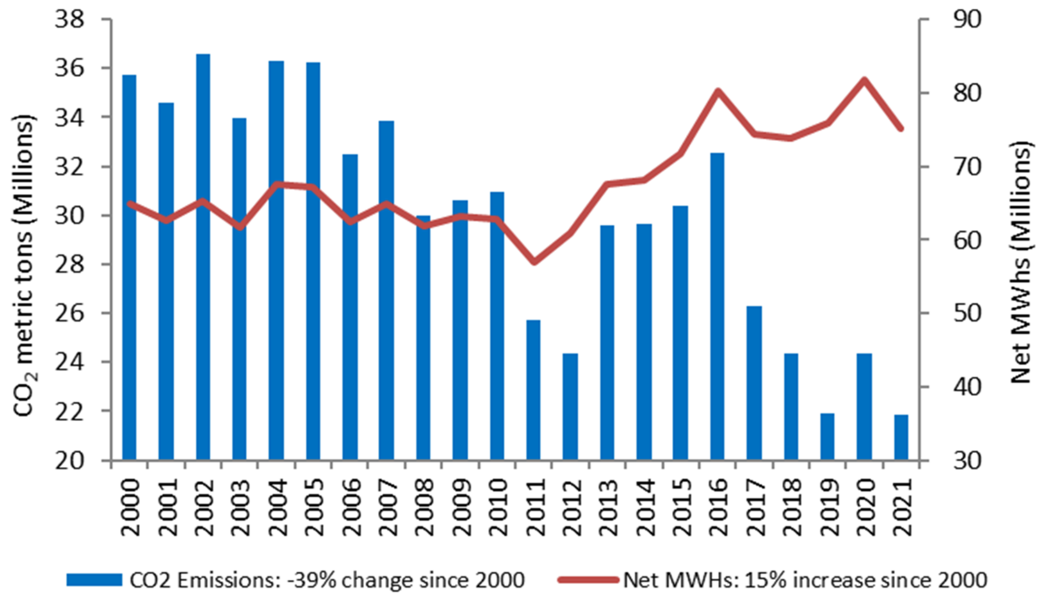
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, the conversion to dry ash handling, and the addition of air pollution controls. This strategy has resulted in significant reductions of air pollutants such as NO_X, sulfur dioxide ("SO_2"), and mercury ("Hg"), as shown in Figure 5.1.2.1, and has also reduced the amount of coal ash generated and the amount of water used.

Figure 5.1.2.1 – Company Annual Reduction in Emissions by Percent



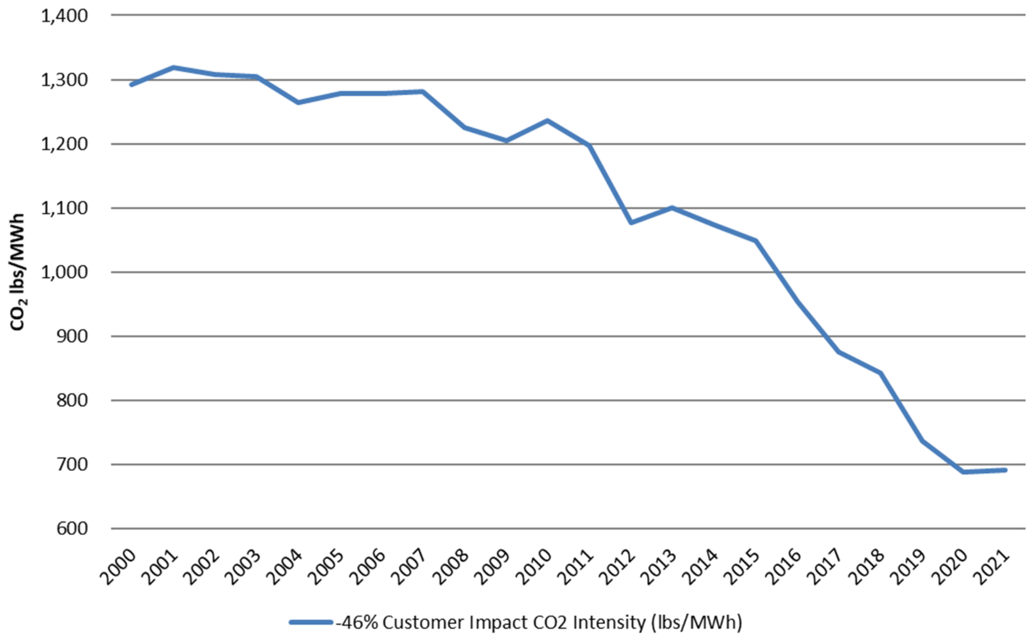
The Company develops a comprehensive greenhouse gas inventory annually. The Company's direct CO_2 emissions (based on ownership percentage) were 21.8 million metric tons in 2021 compared to 24.3 million metric tons in 2020. The Company has been a leader in reducing CO_2 emissions through retiring certain units; building additional efficient and lower-emitting natural gas-fired power generating sources and carbon-free renewable energy sources, such as solar and wind; and maintaining its existing fleet of non-emitting nuclear generation. As shown in Figure 5.1.2.2, from 2000 through 2021, the Company has reduced the CO_2 emissions in tons from its power generation fleet serving Virginia jurisdictional customers by 39%, while power production has increased by 15%.

Figure 5.1.2.2 – Company CO_2 Mass Reductions versus Net Generation



The Company's integrated business strategy has also resulted in significant reduction in CO_2 emission intensity. CO_2 intensity is the amount of emissions per MWh delivered to customers. This calculation includes emissions from any source used to deliver power to customers, including Company-owned generation, PPAs, and net purchased power. As shown in Figure 5.1.2.3, customer impact CO_2 intensity has decreased by 46% since 2000.

Figure 5.1.2.3 – Customer Impact CO_2 Intensity



5.1.3 Power Purchase Agreements

A portion of the Company's load and energy requirement is supplemented with contracted PPAs. The Company has existing contracts with fossil-burning and renewable energy PPAs for capacity of approximately 1,164 MW (nameplate).

For modeling purposes, the Company assumed that its PPA capacity would be available as a firm generating capacity resource in accordance with current contractual terms. These PPA units also provide energy to the Company according to their contractual arrangements. At the expiration of these PPA contracts, these units will no longer be modeled as a firm generating capacity resource. The Company assumed that PPAs 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, supply, or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter 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.

5.2 Evaluation of Existing Generation

The Company continuously evaluates various options with respect to its existing fleet, cognizant of environmental regulations and other policy considerations.

5.2.1 Retirements

The VCEA mandates the retirement of carbon-emitting generation on a specific schedule unless the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric services:

- Chesterfield Units 5 and 6 (coal) and Yorktown Unit 3 (heavy oil) by 2024; and
- All remaining generation units that emit CO_2 as a byproduct of combustion by 2045.

Chesterfield Units 5 and 6 and Yorktown Unit 3 are all scheduled to retire in May 2023. No generation from these units is shown in the plans presented. Retirement notification letters for these stations can be found in Appendix 2B. The Altavista, Hopewell, and Southampton biomass units are no longer retiring by 2028 in all Alternative Plans, and RECs generated by those units can be used for RPS compliance per pending legislation HB2026/SB1231. Separate from these mandates, and consistent with prior Plans, the Company completed two analyses related to retirement of existing units.

First, the Company completed a 10-year cash flow analysis focused on coal-fired, biomass-fired, and large combined-cycle generation facilities under market conditions. The Company evaluated 10-year cash flows under five scenarios using the Base Case commodity price forecast as an underlying market forecast. Unit NPVs were derived by comparing the unit costs, including operations and maintenance and capital, to the total forecasted unit benefits, consisting of energy and capacity revenues (and REC revenues where applicable) for the next 10 years based on the snapshot in time when the analysis was conducted. This analysis allows the Company to view each unit's near-term projected revenue and cost streams in one place, and to determine key drivers for unit profitability.

A positive NPV result indicates that the unit is currently better than market, while a negative value indicates the unit is currently worse than market. These results alone are not comprehensive and cannot exclusively be used to determine whether to continue to operate an existing unit. Other quantitative and qualitative considerations must be prudently factored into such determinations, such as remaining useful life, capacity and energy replacements, system reliability, fuel contracts, transmission system considerations, personnel, impact of continued operation of the unit(s) on the local economy, and environmental benefits, to name a few. The results of the 10-year cash flow analysis are included in Figure 5.2.1.1.

Figure 5.2.1.1: Ten-Year Cash Flow Analysis Results (NPV $ Million)

Units	2023 Plan A	2023 Plan B	Low Capacity Price	High Capacity Price	Est. T&D Impact
Clover 1 - 2	$52	$48	($23)	$110	$0
Mt Storm 1 - 3	$148	$126	($130)	$352	$6
VCHEC	($199)	($206)	($305)	($119)	$16.8
Altavista	$21	$20	$12	$27	$0
Hopewell	$34	$32	$25	$39	$0
Southampton	$36	$35	$27	$42	$0
Rosemary	($4)	($4)	($26)	$16	$0
Bear Garden	$570	$557	$454	$649	$6
Brunswick	$1,217	$1,186	$954	$1,391	$6.5
Chesterfield 7 - 8	$316	$305	$241	$362	$3
Gordonsville 1 - 2	$122	$118	$81	$150	$0
Greensville	$1,600	$1,562	$1,301	$1,792	$6.5
Possum Point 6	$410	$397	$302	$482	$11.7
Warren	$1,600	$1,568	$1,339	$1,771	$0

Note: "Est. T&D Impact" represents the approximate transmission and distribution upgrades that would be necessary to support the unit retirement. This avoided cost is not included in the NPVs shown.

Second, as directed by the SCC, the Company included the same unit-specific data for the units listed in Figure 5.2.1.1 in PLEXOS to allow the model to optimize endogenously the timing of unit retirements. The Company presents these results as part of Alternative Plans A through C, which shows all units running through the Study Period. While a few units had a negative value in the 10-year NPV analysis, all units are positive when reviewed over the 25-year planning horizon shown in Figure 5.2.1.2 and PLEXOS did not select to retire any units.

In Alternative Plans D and E, consistent with prior filings, the Company aimed to determine a glide path to continue to reliably serve customers through the transition to a cleaner energy fleet, taking into consideration components such as capacity factors, performance characteristics, including ramping time, fuel diversity and availability, maintenance requirements, and environmental regulations.

Figure 5.2.1.2: Twenty-Five-Year Cash Flow Analysis Results (NPV $ Million)

Units	2023 Plan A	2023 Plan B	Low Capacity Price	High Capacity Price
Clover 1 - 2	$423	$797	$563	$828
Mt Storm 1 - 3	$1,817	$3,763	$2,915	$3,876
VCHEC	$193	$792	$465	$835
Altavista	$104	$165	$138	$169
Hopewell	$120	$181	$157	$184
Southampton	$125	$186	$158	$190
Rosemary	$27	$35	($39)	$45
Bear Garden	$1,650	$2,440	$2,098	$2,486
Brunswick	$3,670	$5,456	$4,689	$5,559
Chesterfield 7 - 8	$989	$1,603	$1,389	$1,631
Gordonsville 1 - 2	$469	$775	$654	$791
Greensville	$4,692	$6,869	$6,007	$6,984
Possum Point 6	$1,344	$2,103	$1,788	$2,145
Warren	$4,114	$5,827	$5,068	$5,929

It is worth noting that a ten-year cash flow analysis is not the only deciding factor in retiring an existing resource. Modeling in this 2023 Plan is based on normal weather and models the complete system, which does not fully capture the value of a unit that may be based on location, fuel diversity, value in extreme weather scenarios, operational flexibility, and black start capability, among other factors.

The Company has not made any decision regarding the retirement of any generating unit other than Yorktown Unit 3 and Chesterfield Units 5 and 6. Accordingly, the inclusion of a unit retirement in this 2023 Plan should be considered as tentative, based only on a snapshot in time. The Company's final decisions regarding any unit retirement will be made at a future date. Appendix 5J lists the generating units considered for potential retirement in Alternative Plan B.

5.2.2 Uprates and Derates

Efficiency, generation output, and environmental characteristics of units 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 unit ratings have been and will continue to be adjusted in accordance with PJM market rules and environmental regulations. Appendix 5K provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

5.2.3 Environmental Regulations

There are several final, proposed, and anticipated U.S. Environmental Protection Agency ("EPA") regulations that will affect certain units in the Company's current fleet of generation resources. Appendix 5L shows regulations designed to regulate air, solid waste, water, and wildlife.

The following section outlines changes to various environmental regulations since the Company filed its 2020 Plan. The 2020 Plan contains a historical perspective on some of the environmental regulations discussed. ~~Appendix 5L shows regulations designed to regulate air, solid waste, water, and wildlife.~~

Carbon Regulations

Federal Carbon Regulation

The past decade has seen attempts at carbon regulation at the federal level. The Clean Power Plan, announced in 2015 by President Obama, sought to set limits on carbon emissions from power plants. In 2018, President Trump announced the Affordable Clean Energy Rule ("ACE Rule"), which repealed and replaced the Clean Power Plan with a rule that sought to set heat rate efficiency improvements and improved operating and maintenance practices. Both efforts, which were adopted by the EPA under Section 111(d) of the Clean Air Act, saw significant legal challenges.

On January 19, 2021, the D.C. Circuit Court vacated the ACE Rule. On June 30, 2022, the U.S. Supreme Court issued a decision in *West Virginia v. EPA* that limits the scope of the EPA's authority to control greenhouse gas emissions from existing power plants under Section 111(d). This decision will impact how greenhouse gas emissions can be regulated at existing power plants by the EPA in future rulemakings, absent action from Congress. The EPA retains the authority to regulate at the source by proposing mechanisms such as heat rate improvements, but the EPA no longer holds the authority to regulate GHG emissions limits from power production by requiring a shift in electricity production to cleaner renewable energy sources from certain fossil fuel-fired power generation sources. Put another way, the EPA remains empowered to regulate carbon at the power plant level, but not at the economy-wide or electric utility-wide level.

The EPA is currently working on a new set of guidelines to direct states in regulating GHGs from existing fossil-fuel fired generating units within their borders. According to current EPA guidance, the EPA intends to issue a proposed rule in spring 2023, with a final rule expected in spring 2024.

RGGI

Regional Greenhouse Gas Initiative ("RGGI") is a collaborative effort to cap and reduce CO_2 emissions from the power sectors of participating states. Virginia joined RGGI as of January 1, 2021, through regulations, referred to as the CO_2 Budget Trading Rule. As a result, the Company has been required to purchase CO_2 allowances to cover CO_2 emissions from its regulated emissions sources.

On January 15, 2022, Virginia Governor Youngkin issued Executive Order Number Nine ("EO9") Protecting Ratepayers from the Rising Cost of Living Due to the Regional Greenhouse Gas Initiative directing state agencies to take certain actions to "re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it." On March 11, 2022, as directed by EO9, the Virginia Department of Environmental Quality issued a report that presented a path for Virginia to end its participation in RGGI; the report also included an evaluation of the cost and benefits of participation in RGGI in view of all applicable data.

On December 7, 2022, the Virginia Air Board approved the Notice of Intended Regulatory Action to move forward on the draft regulation to repeal Virginia's CO_2 Budget Trading Rule. In accordance with Executive Order 19, which is the Governor's process for developing and reviewing state agency regulations, other executive branches within the government have approved to move forward with the repeal. The proposed repealed regulation went out for public comment on January 30, 2023, and the public comment period closed on March 31, 2023. A public hearing was held on March 16, 2023. The exit from RGGI is expected to be completed by December 31, 2023.

New Source Performance Standards for Greenhouse Gas Emissions

In December 2018, the EPA proposed revised new source performance standards ("NSPS") for greenhouse gas emissions from new, modified, and reconstructed stationary sources under Section 111(b) of the Clean Air Act. This action was never finalized. The EPA is currently reevaluating the NSPS for new and modified sources including what is determined to be the best system of emission reduction. A draft rule is expected in spring 2023. According to the EPA's unified agenda, the expected timeframe on a final rule is the second quarter of 2024.

Proposed Revisions to the Prevention of Significant Deterioration and New Source Review Regulations for Greenhouse Gases

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a prevention of significant deterioration permit for greenhouse gas emissions is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the new source review program and exceed a significant emissions rate of 75,000 tons per year of CO_2 equivalent emissions. There is no expected timeframe for the final rule.

New Proposed Federal Vehicle Emission Standards

On April 12, 2023, the EPA proposed new vehicle standards for light, medium and heavy-duty vehicles for model year 2027 and beyond. The EPA's proposal increases the stringency of the standard year-over-year on a phase-in approach. Through 2055, the EPA projects that the proposed standards would avoid nearly 10 billion tons of CO_2 emissions. The light and medium duty vehicle proposed standards are expected to avoid 7.3 billion tons of CO_2 emissions through 2055 and would also deliver significant health benefits by reducing fine particulate matter. The heavy-duty truck proposal is projected to avoid 1.8 billion tons of CO_2 through 2055.

Ozone National Ambient Air Quality Standards

The ozone national ambient air quality standard ("NAAQS") governs ground-level ozone forming pollutants, including NO_x emissions. The Clean Air Act requires the EPA to review the NAAQS every five years and revise the NAAQS if necessary.

On March 15, 2023, the EPA released a pre-publication of the final federal implementation plan ("FIP") addressing interstate transport for the 2015 Ozone NAAQS. The FIP is intended to resolve the good neighbor obligations with respect to the 2015 NAAQs. Virginia and West Virginia are covered in the FIP. The FIP consists of a combination of methods including a revised Cross-State Air Pollution Rule ("CSAPR") ozone season NO_x emissions trading program with additional restrictions not included in any of the current CSAPR trading programs. Coal-fired electric generating units (excluding circulating fluidized bed boilers) would be subject to daily emission rate limits during ozone season and would have to surrender additional allowances (at a 3:1 ratio), if limits are exceeded after the first 50 tons during the control period.

On December 31, 2020, the EPA published a final decision retaining the 2015 NAAQs of 70 parts per billion ("ppb") as the 2020 NAAQS. As directed by Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," signed by President Biden on January 20, 2021, the EPA undertook a review of the December 2020 decision that retained the 2015 NAAQs. As part of this reconsideration, the EPA is developing a policy assessment to consider all policy-relevant information developed throughout the 2020 review, and to engage with the Clean Air Scientific Advisory Committee Ozone Review Panel. The panel is currently reconsidering the decision to retain the 2015 NAAQs for ozone at 70 ppb for both the primary and secondary limits. According to the EPA's unified agenda, the EPA aims to issue a draft ruling in the second quarter of 2023 and a final rule by the end of 2023.

Particulate Emission Standards

On January 6, 2023, the EPA released a pre-publication version of a proposed rule resulting from its reconsideration of the primary (health-based) NAAQS for particulate matter ("PM NAAQS"). The EPA is proposing to lower the primary annual $PM_{2.5}$ NAAQS from 12.0 micrograms per cubic meter ("ug/m^3") to a level that would fall between 9.0 and 10.0 ug/m^3, while soliciting comment on an alternative annual $PM_{2.5}$ standard within the range of 8.0 to 11.0 ug/m^3. The EPA is proposing to retain the other PM NAAQs at their current levels, including the secondary 24-hour $PM_{2.5}$ NAAQS. According to the EPA's unified agenda, a final rule is expected in the third quarter of 2023.

Mercury & Air Toxics Standards

On March 6, 2023, EPA published a final rule that reinstates the Agency's April 25, 2016 finding that it is appropriate and necessary to regulate hazardous air pollutants emissions from coal and oil-fired electric generating units under Section 112 of the Clean Air Act via the mercury and air toxics standards ("MATS") rule. All of the Company's applicable units are complying with the applicable requirements of the MATS rule.

On April 24, 2023, the EPA published a proposal to tighten certain aspects of the MATS rule which include a lower emission limit for filterable particulate matter and required use of continuous emission monitoring system to demonstrate compliance with the PM limit. Other proposed changes include removal of emission limits for total and individual non-mercury hazardous air pollutants, and elimination of a "startup" definition. The EPA is expecting to come out with a final action by the end of 2023, with the final strategy and implementation likely occurring in the second quarter of 2024.

Coal Combustion Residuals

The Company currently operates inactive ash ponds, existing ash ponds, and coal combustion residual ("CCR") landfills at eight different facilities. In April 2015, the EPA enacted a final rule regulating (i) CCR landfills; (ii) existing ash ponds that still receive and manage CCRs; and (iii) inactive ash ponds that do not receive, but still store, CCRs. This rule created a legal obligation for the Company to retrofit or close all inactive and existing ash ponds over a certain period of time, and to perform required monitoring, corrective action, and post-closure care activities as necessary. Since the rule was enacted, the EPA has reconsidered portions of the rule in response to litigation and petitions for reconsideration. In July 2018, the EPA promulgated the first phase of changes to the CCR rule and continues to issue changes to the CCR rule. In August 2018, the D.C. Circuit Court issued a decision in the pending challenges of the CCR rule, vacating and remanding to the EPA three provisions of the CCR rule. The Company does not expect the scope of the D.C. Circuit Court's decision to affect its closure plans.

Clean Water Act

The Clean Water Act ("CWA") is a comprehensive program that uses a broad range of regulatory tools to protect the waters of the United States, including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms.

Section 316(b)

In October 2014, the final regulations under Section 316(b) of the CWA became effective; these regulations govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The rule establishes a national standard for impingement based on seven compliance options but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two million gallons per day ("MGD"), with a heightened entrainment analysis for those facilities over 125 MGD.

The Company currently has seven facilities that are subject to the final Section 316(b) regulations. Additionally, the Company may have one hydroelectric power facility subject to the final regulations. The Company anticipates that it may have to install impingement control technologies at certain of these stations that have once-through cooling systems. The Company is currently evaluating the need or potential for entrainment controls under the final rule; decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost, and benefit studies.

Effluent Limitation Guidelines

In September 2015, the EPA revised its effluent limitations guidelines ("ELG") for the steam electric power generating category. The final rule established updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to (i) convert from wet to dry or closed cycle coal ash management, (ii) improve existing wastewater treatment systems, and/or (iii) install new wastewater treatment technologies in order to meet the new discharge limits. In April 2017, the EPA granted two separate petitions for reconsideration of the ELG rule and stayed future compliance dates in the rule. In September 2017, the EPA signed a rule to postpone the earliest compliance dates for certain waste streams regulations in the ELG rule from November 2018 to November 2020. However, the latest date for compliance with the regulation remained December 2023.

In October 2020, the EPA published a revised ELG rule that included changes in the requirements for two waste streams, flue gas desulphurization ("FGD") and bottom ash transport waters ("BATW"), applicable to the Chesterfield Power Station and Mount Storm Power Station, respectively. The 2020 ELG rule also extended the compliance deadlines for final compliance with these requirements to December 2025 and offered an extended compliance deadline of December 2028 for facilities choosing to meet restrictive discharge limits or electing to cease coal combustion by that date. The Company is constructing BATW treatment facilities at Mt. Storm Power Station designed to comply with the 2020 ELG rule BATW requirements by March 31, 2024. In addition, the Company will be retiring the last coal-fired generating units at the Chesterfield Power Station during 2023.

On January 20, 2021, President Biden signed Executive Order 13990 directing federal agencies to review rules issued in the prior four years that are, or may be, inconsistent with the President's stated environmental policy. On July 26, 2021, the EPA announced that it was initiating a rulemaking process to determine whether to adopt more stringent limitations than those in the 2020 ELG rules for steam electric generating units. Subsequently, in March 2023, the EPA released a pre-publication version of proposed revisions to the 2020 ELG rule that includes discharge prohibitions on FGD and BATW waste streams. The BATW technology being installed at Mt. Storm Power Station has been designed to comply with the BATW discharge prohibition should it be promulgated. Retirement of the coal-fired generating units at Chesterfield Power Station eliminates any impact of this proposed rule to that station's discharges.

5.2.4 Nuclear License Extensions

The licenses to operate the two nuclear units at the Company's Surry Power Station were renewed by the NRC on May 4, 2021, permitting continued operation through 2052 for Unit 1 and through 2053 for Unit 2. The Company is now completing the upgrades deemed necessary to operate these units in the extended period of operations.

The Company submitted its application to the NRC to renew the licenses for its two units at the North Anna Power Station in August 2020. After the submittal, the Company engaged with the NRC, consultants, and industry partners regarding additional information requested for the application related to certain potential environmental impacts of operating North Anna Units 1 and 2 from 60 to 80 years. The Company submitted supplemental environmental information to the NRC on September 28, 2022. The NRC provided a schedule with application milestones moving forward that reflects an expected decision in July 2024, without intervenors filing contentions. The Company remains confident that it will receive the renewed licenses for these units, which would permit North Anna Units 1 and 2 to continue operating until 2058 and 2060, respectively.

In July 2022, the SCC approved the Company's request for cost recovery related to (i) preparing the subsequent license renewal applications and (ii) upgrading or replacing systems and equipment deemed necessary to operate safely and reliably in the extended period of operation. Based on this approval and the approval / anticipated approval of the subsequent license renewal application by the NRC, all Alternative Plans in this 2023 Plan assume that an additional 20 years will be added to the licenses at both the Surry and North Anna Power Stations.

5.3 Generation Under Construction

See Appendix 3A provides for details on the generation project under construction that the SCC has approved.

5.4 Generation Resources Under Development

The Company currently has solar, wind, energy storage, and CT generation projects under development, along with an LNG facility at one of the Company's existing units. The following sections provide details on these projects, as does Appendix 3B.

The Company has paused material development activities for North Anna 3 following receipt of the combined operating license ("COL") in 2017. The Company is currently incurring minimal capital costs associated with North Anna 3 specific to the administrative functions of maintaining the COL.

5.4.1 Solar, Onshore Wind, and Energy Storage

As part of its on-going efforts to expand the portfolio of renewable energy and carbon-free resources, and to meet the development targets as set forth in the VCEA, the Company has pursued multiple avenues to identify viable projects. The Company annually issues an RFP for new solar (utility-scale and distributed), energy storage, and onshore wind resources, seeking both projects for the Company to acquire and projects for the Company to purchase the output through PPAs. The Company also has sourced projects from outside the RFP process, which have traditionally come in the form of either self-development or bilateral transactions. The Company evaluates all potential projects and PPAs on an equal basis to determine which projects provide the best value for customers. As required by the VCEA, the Company then brings new Company-owned and PPA resources before the SCC for approval as part of its annual plan regarding the development of solar, onshore wind, and energy storage.

5.4.2 Combustion Turbines

Combustion turbines provide firm energy during periods of high demand to ensure grid reliability while supporting the growth of renewable energy resources specifically during periods when intermittent resources are not generating. Dispatchable energy generation will be critical to fill the gaps created when the production from intermittent generation drops but significant load continues. For example, as discussed above in Section 1.3, ***Severe Weather Events***, Winter Storm Elliott showed the need for every generating unit in the Company's fleet to be dispatched to meet the system peak early in the morning when solar resources were not producing energy. This type of extreme weather event threatens system reliability and requires resources to ensure the Company can meet customer demands. As discussed in Section 1.1, ***PJM Load Forecast and Energy Transition Risks***, PJM has specifically identified critical concerns associated with maintaining reliability during the transition to a system built on clean energy resources. CTs provide the capability to quickly dispatch when needed, with a proven history of being highly available, running reliably, and having the ability to provide energy over a longer period of demand. Combustion turbines also can help to address probable transmission system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities that are discussed further in Section 7.5, ***Transmission System Reliability Analyses***, including support for system restoration by providing black start capabilities.

For these reasons, the Company is evaluating sites and equipment for the construction of gas-fired CT units. These new combustion turbines will be dual-fuel capable, have additional onsite backup fuel supply, and be capable of blending hydrogen in the future. Multiple fueling capabilities provide flexibility to endure multi-day extreme weather events when gas supply is limited. Combustion turbines also support system restoration by providing black start capabilities. In order to meet the energy and capacity needs associated with the load forecast and without a commercially viable carbon-free, dispatchable generation alternative, CTs will be the critical component to ensuring grid reliability in the near term.

5.4.3 LNG Facility at Greensville

Greensville County Power Station provides essential, around-the-clock power with the ability to serve more than 350,000 Virginia homes. To maintain a readily available, reliable fuel source for this critical station and potentially others, the Company is proposing to add storage capabilities for LNG. This stored LNG will provide a reliable backup fuel supply to keep gas flowing in the event of a natural disaster, extreme weather, or other fuel supply disruptions or constraints.

The need for this type of backup fuel supply is illustrated by fuel shortages that occurred in recent years, impacting millions of customers. For example, in May 2021, the Colonial Pipeline, which carries gasoline and jet fuel to the Southeastern United States, was shut down for five days due to a cyberattack, resulting in a fuel shortage that affected millions of consumers and airlines along the East Coast. As another example, in Texas in February 2021, extreme winter weather caused a significant portion of the state's electric generating capacity to fail when demand reached historic highs, an issue compounded by failures of the natural gas delivery system, resulting in rolling blackouts and impacting millions of people.

The addition of an LNG facility to support Greensville Power Station and potentially others will reduce the Company's reliance on a single gas pipeline, provide backup to support at least 1,588 MW of generating capacity, and support gas supply available to the Company's fleet. This facility is vitally important to the reliability and resilience of the Company's system.

5.5 Future Supply-Side Generation Resources

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 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, 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 and O&M.

Further analysis is then conducted in PLEXOS to incorporate seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. This analysis more accurately matches 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.

Figure 5.5.1 summarizes the supply-side resource types that the Company reviewed as part of the generation planning process.

Figure 5.5.1 - Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource	PLEXOS Resource
Aero-derivative Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Battery Generic (30 MW) (4H)	Peak	Yes	Varies	Yes	Yes
Combined Cycle - 3X1	Intermediate/Baseload	Yes	Natural Gas	Yes	No
Combined Cycle - 2X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 1X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Heat and Power	Peak	Yes	Varies	No	No
Waste Heat to Power	Peak	Yes	Varies	No	No
Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Fuel Cell	Baseload	Yes	Natural Gas	Yes	No
Nuclear Small Modular Reactor	Baseload	Yes	Uranium	Yes	Yes
Pumped Storage (300 MW)	Peak	Yes	Renewable	Yes	Yes
Solar	Intermittent	No	Renewable	Yes	Yes
Solar (Distributed)	Intermittent	No	Renewable	Yes	Yes
Wind - Offshore	Intermittent	No	Renewable	Yes	Yes
Wind - Onshore	Intermittent	No	Renewable	Yes	Yes
Energy Storage	Peak	Yes	Varies	Yes	No

5.5.1 Supply-Side Resource Options

The following sections provide details on certain newer supply-side resource options the Company has considered. See Section 1.4, ***Small Modular Reactors***, for additional details on small modular reactors as a supply-side option. Previous Plans provide additional details on the more proven technologies, including biomass, CCs, CTs, nuclear, and solar. In addition, Section 5.4, ***Generation Resources Under Development***, provides additional details on generation currently under development, including solar, energy storage, wind, CTs, and a backup LNG facility.

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 and 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, 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-dispatchable renewable resources, such as solar and wind. Modeling for Alternative Plan A included two aero-derivative options, a 40 MW unit and a 90 MW unit. While these units are more expensive on a $/kW basis than standard CTs, they may be needed in the future to provide regulation and reserves or in locations with limited CIRs.

Combined Heat and Power / Waste Heat to Power

Combined heat and power ("CHP") is the use of a power station to generate electricity and useful thermal energy from a single fuel source. CHP plants capture the heat that would otherwise be wasted to provide useful thermal energy, usually in the form of steam or hot water. The recovery of otherwise wasted thermal energy in the CHP process allows for more efficient fuel usage. CHP's reduction in primary energy use through fuel efficiency leads to lower greenhouse gas emissions.

Waste heat to power ("WHP") is a type of combined heat and power that generates electricity through the recovery of qualified waste heat resources. WHP captures heat byproduct discarded by existing industrial processes and uses that heat to generate power. Industrial processes that involve transforming raw materials into useful products all release hot exhaust gases and waste streams that can be captured to generate electricity. WHP is another form of clean energy production.

The Company will continue to track this technology and its associated economics based on site and fuel resource availability, but modeling resources in alternative plans is not feasible without a partner and specific location.

Energy Storage

The term "energy storage" applies to a diverse set of technologies that can store energy at one time and make it available at another time. The technologies range in size, cost, performance characteristics, and application. Energy storage can support the grid in several ways, including improved reliability, increased resiliency, and operational flexibility. Based on the most current information sourced from the EIA, the amount of utility-scale battery storage installed in the entire United States is just over 5,000 MW. Of those 5,000 MW, approximately 400 MW are located within the PJM region.

Until recently, energy storage resources have not been broadly deployed at utility scale, other than pumped hydroelectric storage. In addition to legislation in recent years supporting pumped storage, the GTSA established a pilot program to test different applications of storage, and the VCEA sets targets for the development of energy storage generally in Virginia to enhance the reliability and performance of the generation, transmission, and distribution systems. Incremental incentives were made available for energy storage projects through the federal enactment of the Inflation Reduction Act.

The Company has three BESS currently operational that were approved by the SCC under the GTSA pilot program, one to study solar plus storage, one to study the prevention of solar backfeeding onto the transmission grid at a specific substation, and a third to study storage as a non-wires alternative to reduce transformer loading at a specific distribution substation. The Company filed its first annual report on the pilot program with the SCC on March 31, 2023, in Case No. PUR-2019-00124, including lessons learned from constructing these three BESS. The Company is evaluating additional opportunities for this pilot program, including storage paired with direct current fast charging infrastructure for EVs and another potential project aimed at understanding the ability of storage to provide backup power and resiliency for the Company's customers. Under the GTSA, the Company will also seek opportunities to expand its understanding of non-lithium energy storage technologies by evaluating alternative forms of energy storage, including long duration storage, and establish projects to deploy those technologies where technically and economically feasible.

Separate from the GTSA pilot program, the SCC approved two Company-owned storage facilities (one of which is paired with a solar facility) in March 2022 and an additional stand-alone storage facility in April 2023, all of which are currently in various phases of construction. The SCC has also approved 3 PPAs for stand-alone storage resources and 2 PPAs for solar plus storage resources as prudent over the past two years.

The Company presents its plan for the development of additional energy storage resources in the annual proceeding required by Va. Code § 56-585.5, including its progress to date on energy storage development. See SCC Case Nos. PUR-2020-00134, PUR-2021-00146, and PUR-2022-00124 for more information on the Company's approach to energy storage. As stated in those plans, the Company intends to pursue additional energy storage resources, including opportunities to deploy energy storage as behind-the-meter incentives, non-wires alternatives programs, and peak demand reduction programs. See Section 8.5, ***Battery Storage Pilot Program***, for a description of what the Company has proposed related to energy storage as a non-wires alternative. The Company is also partnering with the Virginia Department of Emergency Management and All Hazards Consortium on a pilot program in support of the Federal Emergency Management Agency Building Resilient Infrastructure and Communities initiative to utilize mobile energy storage systems during emergencies for back-up power to critical locations.

Fuel Cell

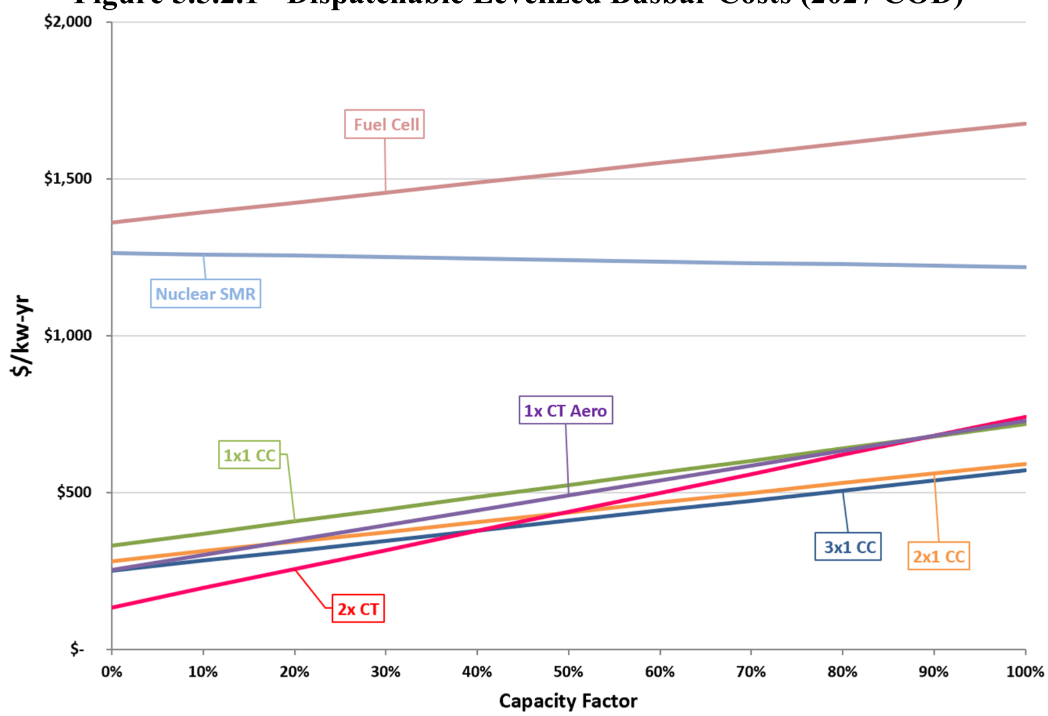
Fuel cells convert chemical energy from hydrogen-rich fuels into electricity and heat; there is no burning of the fuel. Fuel cells emit water and CO_2, resulting in power production that is almost entirely absent of NO_x, SO_x, or particulate matter. Similar to a battery, a fuel cell is comprised of many individual cells that are grouped together to form a fuel cell stack. Each individual cell contains an anode, a cathode, and an electrolyte layer. When a hydrogen-rich fuel, such as clean natural gas or renewable biogas, enters the fuel cell stack, it reacts electrochemically with oxygen (*i.e.*, ambient air) to produce electric current, heat, and water. While a typical battery has a fixed supply of energy, fuel cells continuously generate electricity as long as fuel is supplied. Fuel cells were invented in 1932 and put to commercial use by the National Aeronautics and Space Administration in the 1950s. They are now most common as a power source for buildings and remote areas, but continual improvements in technology are quickly bringing them into wider use.

5.5.2 Levelized Busbar Costs / Levelized Cost of Energy

The Company's busbar model was designed to estimate the levelized energy 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 operation and maintenance costs, expected service life, overnight construction costs, and applicable REC investment or tax credits. These comparisons are also referred to as the levelized cost of energy or "LCOE".

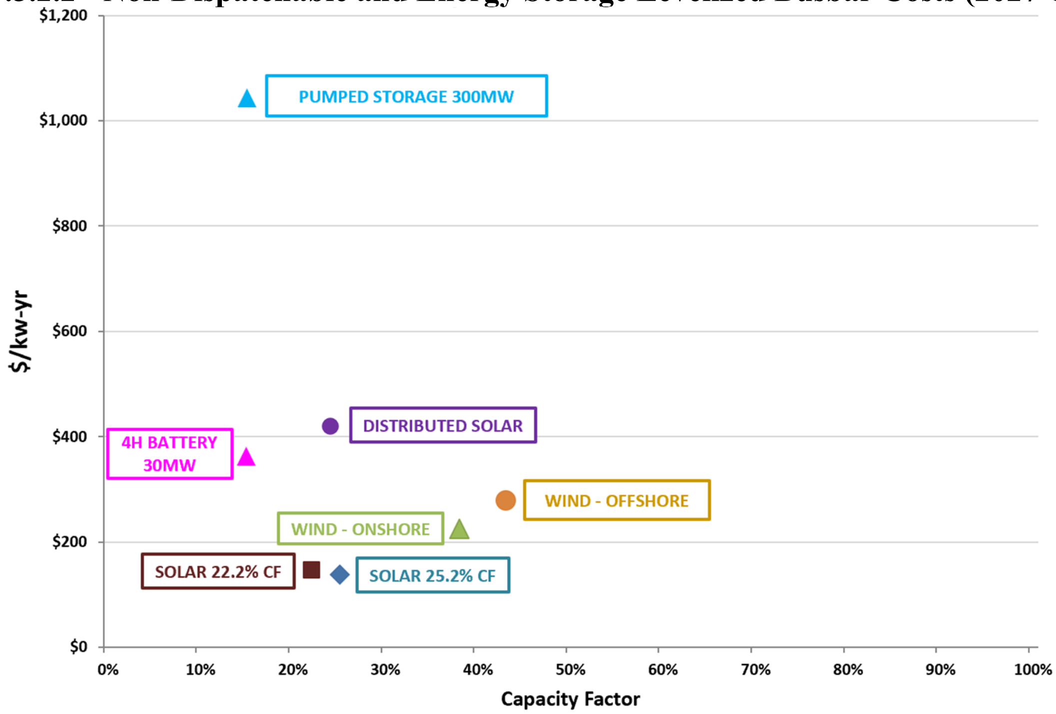
Figures 5.2.2.1 and 5.2.2.2 display high-level results of the busbar model, comparing the costs of the different technologies. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources in terms of the energy and capacity value they provide to customers.

Figure 5.5.2.1 - Dispatchable Levelized Busbar Costs (2027 COD)



Notes: "CC" = combined-cycle; "CT" = combustion turbine; "CT Aero" = aeroderivative combustion turbine; "SMR" = small modular reactor

Figure 5.5.2.2 - Non-Dispatchable and Energy Storage Levelized Busbar Costs (2027 COD)



Note: "4H" = four hour; "CF" = capacity factor. Appendix 5M contains the tabular results of the screening level analysis. Appendix 5N displays the assumptions for heat rates, fixed and variable O&M expenses, expected service lives, and the estimated construction costs.

In Figure 5.5.2.1, 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 LCOE above the lowest combination of curves generally fail to move forward in a least-cost resource optimization. Higher LCOE resources, however, may be necessary to ensure reliability and achieve other constraints such as those required by carbon regulations. Figures 5.5.2.1 and 5.5.2.2 allow comparative evaluation of resource types.

In Figure 5.5.2.1, the value of each 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 PTC or ITC value a given unit may receive.

Figure 5.5.2.2 displays the non-dispatchable and energy storage resources that the Company considered in its busbar analysis. Wind and solar resources are non-dispatchable with intermittent production and lower dependable capacity ratings. Both resources produce less energy at peak demand periods compared to dispatchable resources, requiring more capacity to maintain the same level of system reliability. Non-dispatchable resources may require additional grid equipment and technology changes in order to maintain grid stability.

As shown in Figure 5.5.2.1, CT technology is currently the most cost-effective option at capacity factors less than approximately 40% for meeting the Company's peaking requirements. The CC

3x1 technology is the most economical option for capacity factors greater than approximately 40%. As depicted in Figure 5.5.2.2, solar is a competitive choice at capacity factors of 22% to 25%.

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.

5.5.3 Third-Party Market Alternatives

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 Virginia, the Company issues annual RFPs for solar, onshore wind, and energy storage resources, as discussed in Section 5.4.1, ***Solar, Onshore Wind, and Energy Storage***, and will continue to do so.

In North Carolina, the Company has signed 94 PPAs totaling approximately 722 MW (nameplate) of new solar PPAs. Of these, 696 MW (nameplate) are from 92 solar projects that were in operation as of December 2022. Most of these projects 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.

5.6 Challenges Related to Significant Volumes of Solar Generation

All Alternative Plans in this 2023 Plan include significant development of solar resources, as shown in Section 2.2, ***Alternative Plans***. Based on current technology, challenges will arise as increasing amounts of these non-dispatchable, intermittent resources are added to the system. This section seeks to identify these challenges, which include intra-day, intra-month, and seasonal challenges posed by the interplay of solar generation and load, as well challenges related to system restoration. This section also discusses challenges related to constructing the level of solar generation as shown in the Alternative Plans. In this 2023 Plan, Alternative Plan B best addresses these challenges based on current technology. But the Company stands ready to meet these challenges with continued study, technological advancement, and innovation, and will provide the results of these advancements in future Plans and update filings.

Challenges Related to Capacity

- ELCC values of solar resources have been projected by PJM to drop significantly over time.
- The Company is not aware of any plans for non-Company load serving entities in the DOM Zone to secure additional generation. Historically, non-Company load serving entities in the DOM Zone have depended heavily on imported capacity from other zones.

Challenges Related to Energy

- The issues listed in ***Challenges Related to Capacity***, concerning non-LSE demand apply to energy supply as well.
- Solar generation experiences "non-normal" weather conditions throughout the year when output is significantly less than expected seasonal averages.

- The increased customer demand from data centers has a significantly different seasonal and time-of-day profile than planned solar generation.

Challenges Related to the Solar Production Profile

- The solar production profile is heavily biased towards the middle of the day and produces much less energy in the winter months.
- Heavy cloud cover tends to reduce solar production to a much greater extent than its impact to customer cooling demand.
- After periods of heavy snowfall, solar modules can take several days to get back to expected levels of production.

Challenges Related to Black Start and System Restoration

- At this point in time, solar generation would not be used for black start system restoration due to the impacts intermittent generation would have on grid stability during black start system restoration. Until there is sufficient energy storage to generate electricity at night and to mitigate the impacts of intermittent generation, solar generation will provide little to no value for black start purposes.

Challenges Related to Constructability

- Utility scale solar development requires significantly more land (per kW and per kWh) than any other technology.
- Solar development is most efficient from a kW/acre perspective with flat terrain and competes heavily with agricultural usage.
- Many Virginia communities have actively opposed large scale solar developments.

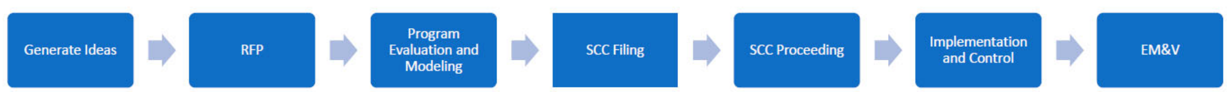
Chapter 6: Generation – Demand-Side Management

This chapter provides a description of the DSM planning process, and an overview of approved, proposed, and rejected DSM programs. See Section 4.1.3, ***Energy Efficiency Adjustment*** for discussion of how the Company adjusted the load forecasts used in this 2023 Plan to account for energy efficiency targets. This chapter also provides the energy efficiency-related analysis required by the GTSA.

There are several drivers that will affect the Company's ability to meet the current level of projected energy and demand reductions, including the cost-effectiveness of the DSM programs when filed, the SCC and NCUC approval of newly filed programs, the continuation of existing programs, the final outcome of proposed environmental regulations and customers' willingness to participate in approved DSM programs.

6.1 DSM Planning Process

The Company has historically used the following process related to its DSM programs:



The GTSA established the DSM stakeholder group, which helps to generate new program ideas. The Company takes those ideas and develops them into more concrete program parameters, which are then compiled into an RFP of candidate program designs and implementation services sent to qualified vendors. The Company develops assumptions for new DSM programs by engaging vendors through a competitive RFP 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. To the extent practical, the Company prefers that the program design vendor is the same vendor that implements the final implementation. The Company believes this enables as much continuity as possible from design to implementation.

Once proposals through an RFP process are received, the Company's energy conservation group works with the Company's supply chain group to systematically review the proposals. Program designs are reviewed for responsiveness to the RFP, practicality of the design, technology requirements, staffing plan, marketing plan, reasonableness of the measures proposed, overlap with existing measures, cost reasonableness, previous experience, work history with the Company, expected ability to deliver the services proposed, and ability of the proposing firm to comply with the Company's terms and conditions, data protection requirements, and financial requirements. Proposals must contain detailed information regarding measure load profiles and market penetration projections in a specific format which allows modeling of the program as a demand-side resource when compared against other resources, including supply-side resources.

Candidate designs that are judged to be reasonable, based on preliminary review, are evaluated for cost-effectiveness from a multi-perspective approach using four of the standard tests from the California Standard Practice Manual: (i) the Participant Test, (ii) Utility Cost Test, (iii) Total Resource Cost Test, and (iv) Ratepayer Impact Measure Test. Each test uses the NPV of costs and benefits. Tests are conducted at a program and portfolio level.

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 developed the Load Management Tool to perform the cost/benefits test leveraging the results obtained from PLEXOS. The inputs into the Load Management Tool are consistent with those in PLEXOS for the 2023 Plan. 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, extension, or modification.

If the programs are cost-effective based on the modeling results, or otherwise legislatively stated to be in the public interest for policy reasons, the programs are then filed with the SCC for approval. The SCC approval process lasts approximately eight months. For the programs that are approved, the Company works with the RFP suppliers to finalize a contract for full implementation of the program. Once all details are finalized, a new DSM program can be launched for participation by eligible customers. Programs that meet the statutory criteria in Virginia are then, when feasible on a smaller scale, brought forth in the following year to the NCUC for consideration.

Finally, the Company conducts evaluation, measurement and verification ("EM&V") of all DSM programs and files the annual EM&V report with the SCC and NCUC each June for the prior calendar year on specific program metrics, including participation, spending, and energy and demand savings.

6.2 Approved DSM Programs

Appendix 6A 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 its plans to achieve each program's penetration goals. Appendices 6B, 6C, 6D, and 6E provide the system-level non-coincidental peak savings, coincidental summer peak savings, annual energy savings, and penetrations for each approved program.

The Company also currently offers one DSM pricing tariff, the standby generation ("SG") rate schedule, to enrolled commercial and industrial customers in Virginia and North Carolina. This tariff provides incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed. One customer is currently on the SG tariff in North Carolina and no customers participate in Virginia. The SG tariff 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 6.2.1 provides estimated load response data for summer/winter 2022.

Figure 6.2.1 - Estimated Load Response Data

Tariff	Summer 2022		Winter 2022	
	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generation	19	2	0	0

The Company modeled this existing DSM pricing tariff over the Study Period based on historical data from the Company's customer information system. Projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future.

6.3 Proposed DSM Programs

On December 13, 2022, the Company filed for SCC approval in Case No. PUR-2022-00210 for five new DSM programs (including one pilot) and four new program bundles as Phase XI programs:

- Residential Customer Engagement Program (EE)
- Residential Efficient Products Marketplace Program (EE)
- Residential Peak Time Rebate Program (DR)
- Non-Residential Custom Program (EE)
- Residential EV Telematics (Pilot Program)
- Residential Income and Age Qualifying Bundle Program (EE)
- Non-Residential Income and Age Qualifying Bundle Program (EE)
- Non-Residential Prescriptive Bundle Program (EE)
- Residential Home Retrofit Bundle Program (EE)

The SCC must issue its Final Order in Case No. PUR-2022-00210 in August 2023.

Appendix 6F provides program descriptions for the proposed DSM programs. Appendices 6G, 6H, 6I and 6J provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each proposed program.

6.4 Future DSM Initiatives

The Company will be conducting an appliance saturation study in 2023 and, once completed, will begin a new DSM market potential study within the Company's service territory. This market potential study will provide additional guidance regarding what additional DSM measures are achievable.

During the first and second quarter of each year, the Company conducts an RFP process to solicit designs and recommendations for a broad range of DSM programs. The Company anticipates continuing this process for the foreseeable future. Within this process, detailed proposals are requested for programs that include measures identified in the most recent DSM potential study, as well as other potential cost-effective measures based upon current market trends.

Load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations for the Company in determining which DSM resources to deploy in the future. The use of these DSM resources largely depends on the circumstances and cannot be prescribed in any definitive manner. The Company will continue to identify and seek approval to implement DSM programs that are cost-effective or meet public policy goals.

As to cost-effective DSM available to respond to the growth of the winter peak, the Company's Distributed Generation Program is currently available to eligible non-residential customers in Virginia and provides dispatchable demand savings during winter periods to non-residential customers who meet participation requirements based upon size. The Company also offers a demand response residential smart thermostat control program, which also provides winter demand and energy savings. Further, the Company's other proposed DSM programs noted in Section 6.3, ***Proposed DSM Programs***, address both summer and winter peaks as well as energy requirements. While demand response programs can be used to reduce peak periods explicitly, energy efficiency programs can also provide reductions during winter hours. The Company is also actively involved with and participating in the DSM stakeholder process, as required by the GTSA and led by the SCC-appointed independent moderator, to further assist the Company in identifying potential opportunities for future energy efficiency and demand response programs and pilots. This effort will hopefully lead to future DSM initiatives that will address both summer and winter peak hours.

Appendices 6K and 6L provide the system-level coincidental peak savings and energy savings for the generic undesignated EE programs.

6.5 Rejected DSM Programs

A list of the rejected DSM programs from prior integrated resource planning cycles is shown in Appendix 6M. Rejected programs may be re-evaluated and included in future DSM portfolios.

6.6 GTSA Energy Efficiency Analysis

Enactment Clause 18 of the GTSA required, "That as part of its integrated resource plans filed between 2019 and 2028, any Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, shall incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; reduction in emissions; and reduction in the utility's carbon intensity."

In its 2021 DSM filing, Case No. PUR-2021-00247, the Company filed a long-term plan for the Company's DSM initiatives with the end goal of setting forth an achievable strategy for meeting the VCEA energy efficiency targets, as well as the state energy and policy goals noted above. The long-term plan provides a vision and pathways for making every practicable effort to achieve the legislative goals over short-, medium-, and long-term time frames. The long-erm plan addresses: (i) strategic vision; (ii) achievability of GTSA and VCEA energy efficiency goals; (iii) risks, challenges, and opportunities stemming from legislative and regulatory changes; (iv) sector profiles, program design recommendations, and implementation pathways aligned with goals and high-level timelines; (v) approaches for adapting to an evolving customer market and advancements in technology; and (vi) high level forecast of energy and demand impacts, program costs, and cost-effectiveness.

The Company immediately began addressing the recommendations contained within the long-term plan and has made proposals to the SCC consistent with the recommendations therein as part of its filings for DSM Phases X and XI. The energy efficiency adjustments described above include the projected energy efficiency savings associated with the approved DSM Phase X, and the Phase XI savings will be incorporated into future Plans if approved by the SCC.

In particular, the Company notes that as part of its long-term plan for energy efficiency measures, the Company has projected spending at least 15% of all DSM-related spending on programs targeted towards low-income, elderly, and veteran populations. Indeed, the Company's DSM portfolio inclusive of Phase XI includes 15.4% of all DSM program costs designed to benefit vulnerable customers.

The continued implementation of the approved DSM programs will further carbon intensity reduction goals, reduce the number of RECs required for RPS compliance, and benefit participating customers through lower energy usage and resulting bills. The Company will continue to actively participate in the stakeholder forum, which provides transparency and inclusivity in the DSM planning process as part of its efforts to achieve the DSM policy goals set by the Commonwealth.

Enactment Clause 18 of the GTSA also directed that utility considerations of energy efficiency within its long-term plan shall include analysis of the following:

- Energy efficiency programs for low-income customers in alignment with billing and credit practices;
- Energy efficiency programs that reflect policies and regulations related to customers with serious medical conditions;
- Programs specifically focused on low-income customers, occupants of multifamily housing, veterans, elderly, and disabled customers;
- Options for combining distributed generation, energy storage, and energy efficiency for residential and small business customers;
- The extent that electricity rates account for the amount of customer electricity bills in the Commonwealth and how such extent in the Commonwealth compares with such extent in other states, including a comparison of the average retail electricity price per kWh by rate class among all 50 states;
- An analysis of each state's primary fuel sources for electricity generation, accounting for energy efficiency, heating source, cooling load, housing size, and other relevant factors; and
- Other issues as seem appropriate.

These items are addressed in the subsequent sections.

6.6.1 Considerations for Certain Customers Groups and Options for Combining Distributed Generation, Energy Storage, and Energy Efficiency

The Company's existing Residential Income and Age Qualifying Home Improvement Program provides in-home energy assessments and installation of select energy-saving products at no cost to eligible participants. The Program is available to qualified customers in the Company's Virginia service territory who earn 60% state median or area median income, whichever is higher. It is also available to customers who are 60 years or older with a household income of 120% of the state or area median income. The Program is available to qualified individuals living in single-family homes, multifamily homes, and mobile homes.

The Company also offers the House Bill 2789 (Heating and Cooling/Health and Safety) Program, which provides incentives for the installation of program measures that reduce residential heating and cooling costs and enhance the health and safety of residents, including repairs and improvements to home heating and cooling systems and installation of energy-saving measures in the house, such as insulation and air sealing. A companion program, the HB 2789 solar component, offers incentives to participants of the first component for the installation of photovoltaic solar panels at their residence. As with the Company's other low-income programs, the Company partners with Weatherization Service Providers ("WSP") to perform community outreach and install program measures to eligible customers.

Additionally, the Company offers certain EnergyStar measures such as EnergyStar appliances, EnergyStar ceiling fans, and EnergyStar windows to low-income customers. And, in its most recent DSM filing update in Case No. PUR-2022-00210, the Company proposed a bundled version of its income and age qualifying programs to ensure differing program offerings did not expire and to promote greater operational efficiencies with the WSP network in the field, which consists of non-profit providers performing the program field work and installing select energy-saving program measures. This regulatory matter is pending, with a final order expected in the latter part of summer in 2023.

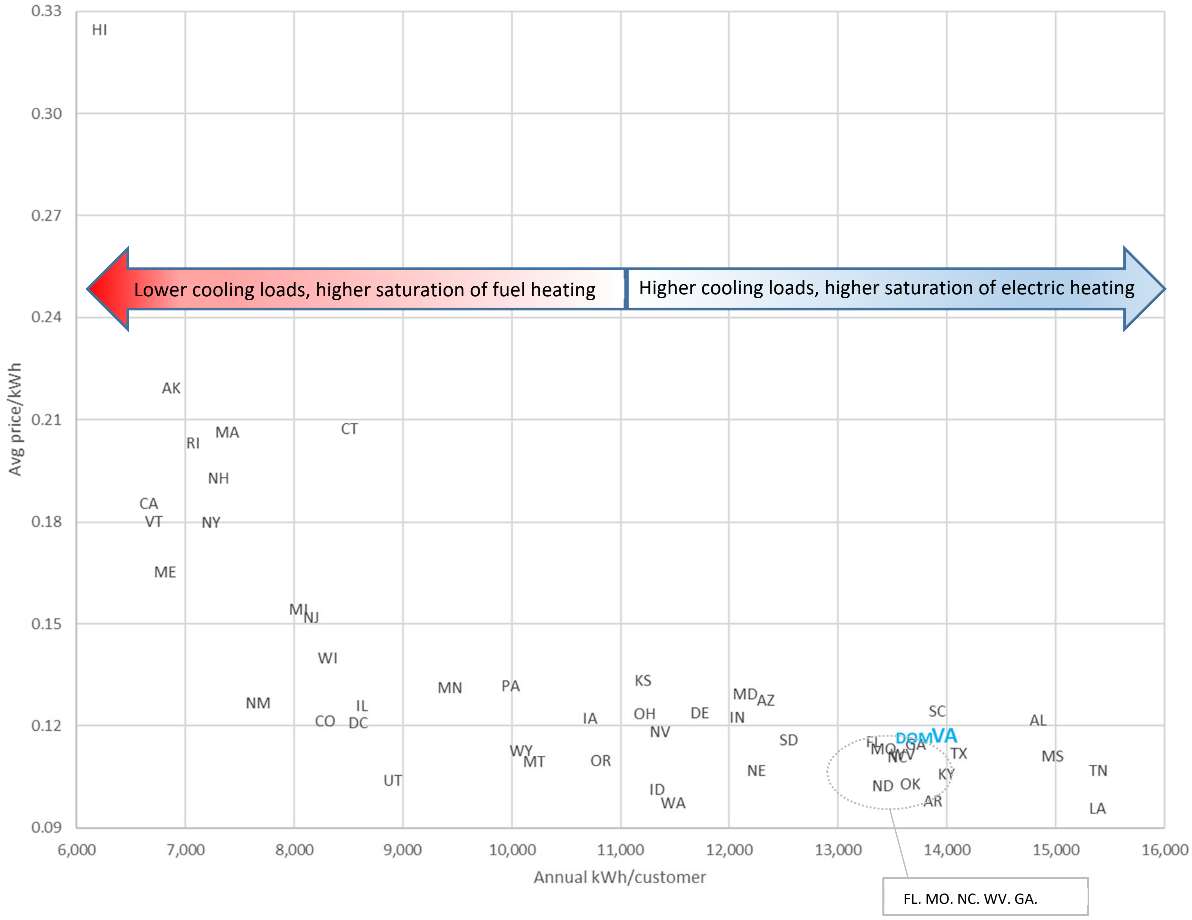
Separate from program proposals, a special subgroup focused on low-income DSM program improvements meets as part of the stakeholder process and making valued suggestions for future program improvements that will result in better alignment with the state's federally funded program. The Company has and will continue to work with the Department of Housing and Community Development to establish alignment with programs where helpful and beneficial.

6.6.2 Electricity Rate and Consumption Comparison

Electricity bills are driven by a combination of electricity rates and electricity consumption. The following charts show where each state and the Company falls by electricity rate and consumption.

In the residential sector, the Company and Virginia as a whole fall within a cluster of mostly southern states with below-average rates and relatively high consumption. The consumption level reflects a high saturation of electric heating equipment compared to other parts of the U.S., paired with high cooling loads.

Figure 6.6.2.1 – States by Residential Average Price per kWh and Consumption per Household

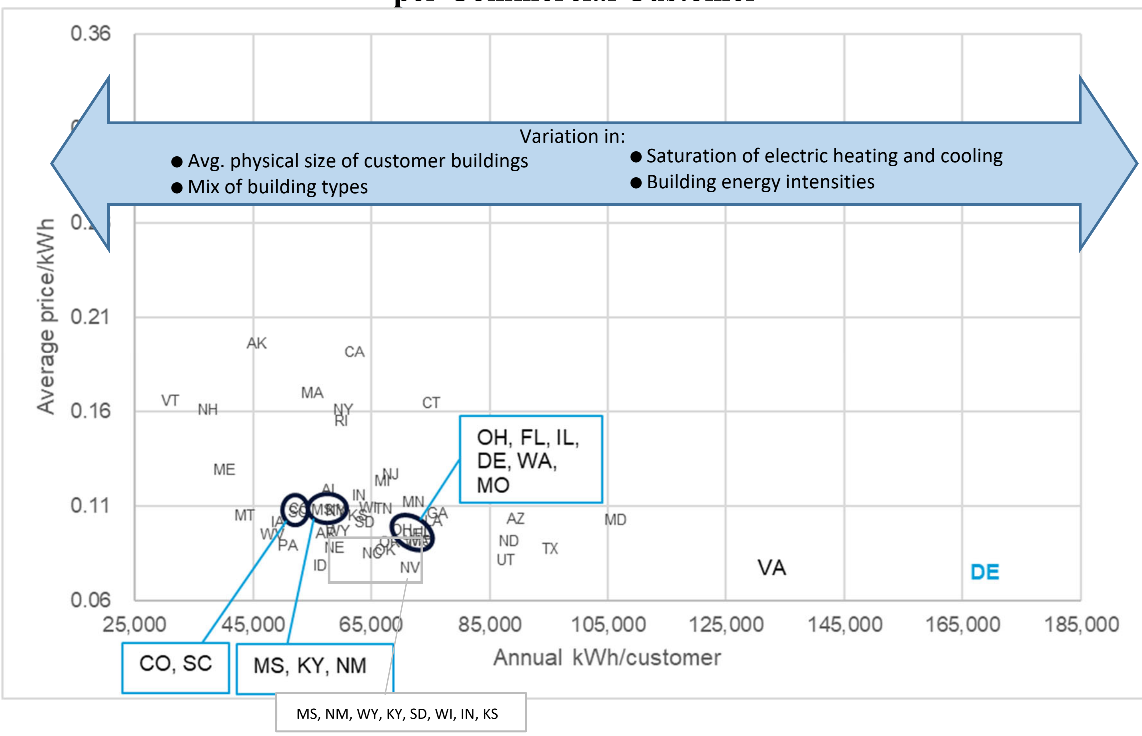


Notes: U.S. Energy Information Administration. Table 5A, Residential Average Monthly Bill by Census Division, and State (Annualized), https://www.eia.gov/electricity/sales_revenue_price/.
U.S Energy Information Administration, Annual Electric Power Industry Report, Form EIA-861 detailed data files, Year: 2021, https://www.eia.gov/electricity/data/eia861/.

In the commercial sector, Virginia is an extreme outlier in consumption per customer, averaging more than 130,000 kWh per year. The Company is one of three utilities in Virginia with average commercial consumption over 100,000 kWh per year; the others are the City of Harrisonburg, Appalachian Power Co., and Virginia Tech Electrical Services. In contrast, the utility with the lowest average commercial consumption is Northern Neck Elec Coop, Inc with less than 16,000 kWh per commercial customer.

The primary drivers of commercial consumption are the size of the customer (i.e., building square feet, number of employees) and the type of building activity. Denser urban areas tend to have larger commercial buildings and therefore higher average commercial consumption, and the Company's service territory captures many of Virginia's densest urban areas. The Company also has a high concentration of data centers among its commercial customers. Data centers are extremely energy intensive, as the densely packed computing equipment they contain produces waste heat that drives high space cooling loads. Because of the extreme differences among commercial customers, building efficiencies are typically compared based on energy intensity (*i.e.*, energy use per square foot) and only among similar building types (*i.e.*, offices with offices and restaurants with restaurants). Unfortunately, data was not available to calculate energy intensity for each state, or to make more granular comparisons.

Figure 6.6.2.2 – States by Average Commercial Price per kWh and Average Consumption per Commercial Customer



Note: U.S. Energy Information Administration. Table 5B. Commercial Average Monthly Bill by Census Division, and State (Annualized). https://www.eia.gov/electricity/sales_revenue_price/.

6.6.3 National Comparison of Primary Fuel Sources for Generation

The Company engaged DNV GL Energy Insights U.S.A. ("DNV GL") to analyze fuel source for generation, as well as the additional metrics referred to in the legislation. This analysis is provided in Appendix 6N.

6.6.4 Other Relevant Issues for Energy Efficiency Analysis

DNV GL, on behalf of the Company, also periodically assesses both the current stock of appliances through an appliance saturation study, and the potential for electric energy (kWh) and demand (kW) savings from Company-sponsored DSM programs through a market potential study of both residential and commercial customers. The most recent iteration of this process is currently underway, and results are expected by late 2023 or early 2024. The results will include:

- Estimates of the magnitude of potential savings on an annual basis;
- Estimates of the costs associated with achieving those savings; and
- Calculations of the cost-effectiveness of the measures based on the estimates above from a total resource cost perspective assuming PJM market price estimates.

The Company and DNV GL conducted previous market potential studies in 2015, 2017 and 2020. Appliance saturation studies and residential conditional demand analyses were conducted in 2013, 2016, 2019-2020, and included mail and electronic surveys of residential and commercial customers.

The market potential studies estimate three basic types of energy efficiency potential:

- Technical potential: The complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective.
- Economic potential: The technical potential of those energy efficiency measures that are cost-effective when compared to supply-side alternatives.
- Achievable program potential: The amount of savings that would occur in response to specific program funding, marketing, and measure incentive levels. In this study, the Company looked at the potential available under two funding scenarios—50% incentives and 75% incentives.

The Company, through its DSM stakeholder process, uses the information contained in the market potential studies to help develop ideas for potential DSM programs to include measures that may be cost beneficial. The most recent market potential study is typically released with a Company solicitation for DSM programs.

6.7 Overall DSM Assessment

In this 2023 Plan, there is a total reduction of 1,786 GWh by 2023 in DSM-related savings. By 2028, there are 3,696 GWh of reductions included in the PLEXOS modeling for this 2023 Plan. Projected energy savings include reductions from identified sources (*i.e.*, DSM programs approved by the SCC), as well as unidentified sources (*i.e.*, "generic" DSM as discussed in Section 4.1.3, ***Energy Efficiency Adjustment*** and below). For modeling purposes, neither the identified nor the unidentified sources included free-ridership effects. If these sources had included free-ridership effects, the reductions by 2023 and 2028 would be 1,858 GWh and 3,719 GWh, respectively. Projected savings attributable to DSM programs in 2028 are shown in Appendix 6O.

At the end of the Planning Period (*i.e.*, 2038), energy reductions projected for the identified DSM programs are approximately 1,468 GWh. This compares to 1,373 GWh identified in the 2020 Plan. Most of the increase in energy reductions is attributed to the additions of the Phase IX and Phase X programs. The capacity reductions at the end of the Planning Period for the identified DSM programs are 433 MW in this 2023 Plan. This compares to 383 MW in the 2020 Plan. Most of the increase in capacity reductions is attributed to the additions of the Phase IX and Phase X programs.

In this 2023 Plan, the unidentified DSM resources are presented as an unidentified generic block of energy efficiency reductions to meet the GTSA and VCEA requirements, as explained in Section 4.1.3, ***Energy Efficiency Adjustment***. That section also includes a discussion of the energy efficiency reductions used as adjustments to the load forecast in this 2023 Plan. Figures 4.1.3.1 and 4.1.3.2 show these energy efficiency energy and capacity adjustments, respectively.

Appendix 6P presents a comparison of the Company's expected demand-side management costs relative to 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 evaluation, measurement, and verification 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 Appendix 6P.

Notably, 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 are the appropriate way to evaluate DSM programs when comparing to equivalent supply-side options and are the methods the Company uses to screen DSM programs.

Chapter 7: Transmission

This chapter provides an overview of the transmission planning process, as well as a list of current and future transmission projects. In addition, this chapter provides the results of the system reliability analyses performed to assess the potential effect of retiring all generating units that emit CO_2 as a byproduct of combustion by 2045.

7.1 Transmission Planning

The Company's transmission system is responsible for providing transmission service: (i) for redelivery to the Company's retail customers; (ii) to Appalachian Power Company, Old Dominion Electric Cooperative, Northern Virginia Electric Cooperative, Central Virginia Electric Cooperative, and Virginia Municipal Electric Association for redelivery to their retail customers in Virginia; and, (iii) to North Carolina Electric Membership Corporation and North Carolina Eastern Municipal Power Agency for redelivery to their customers in North Carolina (*i.e.*, collectively, the DOM Zone). Also, several independent power producers are interconnected with the Company's transmission system and are dependent on the Company's transmission system for delivery of their capacity and energy into the PJM market.

The Company is part of PJM, which is currently responsible for ensuring the reliability of, and coordinating the movement of, electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. The Company also is part of the Eastern Interconnection transmission grid, meaning its transmission system is interconnected, directly or indirectly, with all of the other transmission systems in the United States and Canada between the Rocky Mountains and the Atlantic Coast, except for Quebec and most of Texas. All of the transmission systems in the Eastern Interconnection are dependent upon each other for moving bulk power through the transmission system and for reliability support.

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. Federally mandated NERC Reliability Standards constitute minimum criteria with which all public utilities must comply as components of the interstate electric transmission system. Moreover, the Energy Policy Act of 2005 mandates that electric utilities follow these NERC Reliability Standards and imposes fines for noncompliance of approximately $1.3 million per day per violation.

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; 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 is actively involved in supporting the PJM RTEP process.

The Company also evaluates its ability to support expected customer growth through its internal transmission planning process. The results of these evaluations 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.

7.2 Existing Transmission Facilities

The Company has approximately 6,800 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.

7.3 Transmission Facilities Under Construction

A list of the Company's transmission lines and associated facilities that are under construction can be found in Appendix 7A. Through participation in the PJM RTEP as well as regional, inter-regional, and sub-regional studies described in Section 7.1, ***Transmission Planning***, the Company annually assesses the reliability and adequacy of the interconnected transmission system to ensure the system is adequate to meet customers' electrical demands both in the near-term and long-term planning horizons.

7.4 Future Transmission Projects

Appendix 3C provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM as part of the RTEP process.

7.5 Transmission System Reliability Analyses

In 2020, the Company provided an initial overview of the reliability analyses that it would need to perform to investigate the probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generators. The Company has included and will continue to include the up-to-date reliability analyses in its integrated resource plans and update filings.

Based on the time it takes to complete this type of analysis, the Company used preliminary versions of Alternative Plans A through E in this 2023 Plan and the 2022 PJM Load Forecast. The results and issues identified in this chapter are high level and preliminary, and the Company made several simplifying assumptions. As the contours of future technical challenges that the transmission system will encounter are identified and understood in greater detail, the Company will develop a comprehensive transmission plan that addresses them.

Overall, the results of the Company's analyses show that Alternative Plans D and E will severely challenge the ability of the transmission system to meet customers' reliability expectations. For example, prolonged cold weather or multiple days of clouds and rain will greatly challenge transmission system operators who must balance load and generation resources in real-time operations while also maintaining compliance with NERC reliability requirements. While the Company will be able to develop a transmission expansion plan that will allow for the reliable operation of the transmission system, Alternative Plans D and E would require an investment level that exceeds current transmission level expenditures and would likely exceed the future transmission level costs initially identified in the 2023 Plan.

The reliability analyses performed rely heavily on the capability to import power from PJM, but the reality is that all the Company's neighbors are facing the same generation challenges, meaning that importing power and energy at any time in a year will become more scarce. The Company will continue to study the scarcity of dependable resources within the PJM region as retirements are announced and the grid becomes increasingly reliant on renewable energy resources. In addition, given the significant increase in load in the 2023 PJM Load Forecast compared to the 2022 PJM Load Forecast, the potential reliability concerns identified are likely understated.

7.5.1 Inertia and Frequency Response

Electrical inertia is a system's capacity to resist changes in electrical frequency or frequency response, which is the real-time balance between generation and load. The electrical inertial response, or "inertial response," acts to overcome an immediate imbalance between power supply and demand. Electrical inertia directly relates to the reservoir of stored kinetic energy inherent to traditional rotating synchronous generators on the Company's system. Inertia allows the electric grid to control the frequency deviations that occur all the time, which are caused by events such as load changes, transmission and distribution outages, generation shedding, and system instability. Synchronously rotating machines provide a minimum critical level of inertia. Future technological advances will enable the inertia to be provided as "virtual inertia" by grid-forming inverters with rotating inertia behind them, such as wind turbines or battery storage systems. However, most of today's solar, wind, and storage inverters are of a grid-following type and cannot supply virtual inertia. This can lead to significant problems in managing system frequency, leading to a less reliable electric grid under the high penetration of inverter-based generation resources.

Accordingly, examining the synchronous inertial and frequency responses of the Company's system is critical because these two criteria provide insights into the power system's total frequency support. Theoretical and software simulation methods have been explored to examine these criteria and investigate which alternative plans can ensure acceptable frequency support. Analyzing inertial and frequency response for the DOM Zone depends on the PJM system's expected generation technology mix for the coming years.

The Company evaluated the expected generation technology mix shown in preliminary versions of Alternative Plans A through E in terms of installed capacity together with the installed reserves for the year 2027. Except for Alternative Plan A, which has a positive margin of 3,275 MW, Alternative Plan B through E had negative installed margins. Specifically, system net resources (*i.e.*, generation + storage – load – imports) decrease in the year 2027 by 4 to 7 GW and in the year 2035 by 5 to 8 GW as compared to the year 2021 in the 2022 PJM Load Forecast. The reduction in generation resources and the increase in electric demand will have a significant impact on system reliability; specifically related to less fault current and system inertia, and reduced import capabilities.

The data shows the deterioration of inertial response as the Company's system moves away from relying on large synchronous generation and imports for frequency regulation. This study verifies the system's inertia trend. The net-load imbalance must be met with imports scheduled ahead of time or in real time to ensure flexible reserves can adequately accommodate electricity demand shifts or generation changes from intermittent resources. However, the fast and primary frequency response study was simplified due to present-day simulation tools' limitations and available information. Specifically, a simplified model of the Company's system is represented as a single bus area connected to the PJM system through an equivalent intertie.

The inertial and primary frequency response of the DOM Zone to the loss of the Greenville Power Plant at 1,652 MW was analyzed for preliminary versions of Alternative Plans A through E and for each year between 2022 and 2036. The analysis was conducted at the two bookends of import capability, between (i) the Company and Eastern Interconnect—namely, fully interconnected at a 5,000 MW import capability—and (ii) the Company is islanded with a zero MW import. For Alternative Plan A, the frequency response measured by the expected rate of change of frequency is around 0.08 hertz per second ("Hz/s") when connected with the Eastern Interconnect and rises to 0.5 Hz/s when the DOM Zone is islanded; both did not exceed the highest acceptable threshold of 1 Hz/s. However, keeping minimum dispatchable resources online is not necessary if the Company's system is connected to PJM for Alternative Plans A through E.

PJM represents the non-dispatchable and intermittent resources with a dependable capacity rating in its FERC-approved RTEP planning process. This capacity rating is designed to match the average output of intermittent resources in PJM's load zones during peak summer loading conditions. However, it misses the range of conditions that the electric system may have to withstand, such as timeframes when intermittent generation output is close to 100% of its nameplate rating or during winter loading conditions when the solar generation output is close to zero. Additionally, the study assessed energy adequacy that characterizes the potential risk of load shedding under normal and extreme conditions over a year in order to capture the time sequence issues of the renewable energy output. The inertia and frequency response study analysis simulated several scenarios of renewable and load profiles using hourly resolution (*i.e.*, 8,760 analysis) considering transmission import capability under various likely system operating conditions.

The Company has historically relied on imports from the PJM system to serve the needs of the territory's load. However, the DOM Zone's import capability in the year 2027 under various contingency criteria (*e.g.*, N-1, and N-1-1) for three operating scenarios ranges between 1,077 MW in winter peak, 2,072 MW in summer peak, and 5,530 MW in shoulder scenarios. These import capability limits are significantly lower than the DOM Zone's historical import levels, which reached 6,000 MW. Once again, none of the generation portfolios shown in preliminary versions of Alternative Plans A through E have sufficient resources to serve the peak load without imports. The Company will continue to work and plan to PJM's load deliverability test to ensure the Company is providing adequate import capabilities to meet the customer's demand.

The DOM Zone will experience significant changes over the coming years: the peak load will increase, the synchronous generation will decrease, the import capability will decrease, and the energy storage will increase. The shift from a resource mix currently dominated by thermal, synchronous generation to one dominated by intermittent renewable generation in the next 10 to 15 years will challenge the Company's ability to meet demand around the clock with clean and reliable power. Combined with insufficient transmission import capability from PJM, these factors will reduce net dependable resources for Alternative Plans A through E, ranging between 4.5 to 7 GW by 2027 and 5.2 to 8 GW by 2035. A weaker transmission system does not provide adequate inertia or frequency to respond to or sustain faults on the grid which traditional rotating generation or synchronous condensers provide.

Notably, the situation becomes more challenging based on the higher load growth shown in the 2023 PJM Load Forecast when compared to the 2022 PJM Load Forecast. The Company will incorporate updated load forecast into its reliability analyses in future filings.

7.5.2 Short-circuit System Strength

A short circuit, also known as a fault, is a system disturbance, such as a tree branch falling across electrical lines. When these short-circuit events occur, quickly removing the faulted energized equipment from service is critical for (i) ensuring personnel and public safety, (ii) preventing or reducing equipment failure, and (iii) maintaining the electric grid's stability. Currently, protection and control systems—comprised of relays, circuit breakers, reclosers, and fuses installed across the entire system—remove equipment within milliseconds to seconds. In today's electric grid, a short circuit typically results in a spike in electrical current to that point and depressed voltage around the location of the fault. In a grid with a high density mix of transmission lines and synchronous generation the grid is considered strong and voltage recovers quickly from faults and disturbances enhancing the grid's stability. However, when the transmission and synchronous generation mix dissipates, the system becomes inherently weaker leading to a less stable system. Detection and quick recovery from disturbances occurs today because traditional rotating synchronous generators supply a significant amount of current during short-circuit events. The protection and control systems in operation today—across the entire system in generation plants, transmission and distribution substations, distribution circuits, and even inside customer facilities and homes—are all primarily designed to remove short-circuit events by detecting very high currents.

Inverter-based resources, such as solar and wind, do not provide any significant current increase during short-circuit events; rather, they provide either no change in current or only a nominal amount during short-circuit events. As traditional rotating synchronous generators are retired and replaced with inverter-based generation, the system will likely experience a fundamental change in short-circuit behaviors across all grid levels, specifically lowering short circuits' currents and strength. This will cause the Company's existing protection and control systems, which are installed across the entire system, to have major challenges in detecting these short-circuit events and protecting the system, personnel, and the public.

The short-circuit strength study started with modeling the future resource portfolio within the transmission grid using PJM's RTEP 2027 model, with a focus on the ability of the Company's system to integrate the inverter-based resources and the need for mitigations in the form of synchronous condensers. The effective short circuit ratio ("ESCR") was calculated at each inverter point of interconnection and compared to an acceptable threshold. ESCR was adopted for this study due to its ability to account for the impact of multiple inverter-based resources in close electrical proximity. The ESCR calculation utilized PJM's RTEP 2027 model with the following assumptions:

- Point of interconnection at each inverter-based resource is set to the nearest transmission bus (69 to 500 kV) in order to focus only on bulk system issues and not internal plant issues.
- Only inverter-based resources with grid-following inverters are considered.
- Stand-alone battery storage systems are assumed to have grid-forming inverters and thus are excluded from the analysis.

Based on this analysis, system short-circuit strength in 2027 is deficient at 29 points of interconnection in the Outer Banks and Virginia Beach subzones. Specifically:

- All 745 MW of inverter-based resources in the Outer Banks and Virginia Beach failed the test, while 54.7% of the 303 MW of inverter-based resources in Suffolk failed and 20.6% of the 2,147 MW of inverter-based resources in the PJM zone failed.
- If 388 MW of inverter-based resources are reduced, mainly in the Outer Banks, PJM, and Suffolk zones, the remaining inverter-based resources will pass the test.

To mitigate this problem, adding three synchronous condensers, such as SMRs or other rotating generation, totaling 800 MVA would improve ESCR, and all 6,779 MW of inverter-based resources would pass the test. Alternatively, reducing the solar and wind interconnections by 388 MW would mitigate the problem. As the generation mix changes, the Company will continuously reevaluate the system short-circuit strength and address as necessary.

7.5.3 System Restoration and Black Start Capabilities

Large-scale blackouts negatively impact the public, the economy, and the power system. A proper black start system restoration plan can help to restore power quickly and effectively. Black start—which restores electric power stations and the electric grid without relying on external connections—is the most critical scenario for system restoration. A black start unit is a generator that can start from its own power without support from the power grid, which is essential in the event of a major system collapse or a system-wide blackout. Black start units, and the generation included in the system restoration plan, must be available 24/7 and must have constant and predictable output when operational. These requirements provide difficulties for solar- and wind-generation resources, causing challenges to future black start restoration plans that will need to be studied and resolved. In addition, current black start restoration procedures start from the transmission system and quick-start synchronous generation stations and then work toward restoring the distribution grid. However, with significant DERs, system restoration procedures must be evaluated to account for these DERs, including an investigation into new DER technology like grid-forming inverters used in microgrids.

7.5.4 Future Technology Considerations

As the grid continues to evolve and develop with renewable energy resources, so must the technology used to monitor, control, and transport energy. While technological advancements have been made in some of these areas, much is still to be learned and developed. Such technologies can include, but are not limited to power quality, reactive resources and voltage control, grid monitoring and control capabilities, energy storage requirements, and high-voltage direct current transmission. Future enhancements in power quality will have to be considered because as variable inverter-based generation increases so do the voltage and frequency fluctuations and the harmonics, which can cause a variety of issues on the grid. For reactive resources and voltage control, the Company will have to continue to look at flexible alternative current transmission systems devices, synchronous condensers, and other reactive technologies to help support the electromagnetic fields required to control voltage levels as traditional voltage regulation devices that adjust reactive power like traditional rotating synchronous generators are being replaced with inverter-based generation.

The addition of DERs and the growth and development of EVs and other electrification activities will require future development and enhancements of grid monitoring and control capabilities. Energy storage will become vital to the Company as it moves away from traditional synchronous generation to inverter-based renewable generation due to the intermittence and uncertainty of wind and solar. The Company is already making strides in using energy storage to enhance system reliability as discussed in Section 8.5, ***Battery Storage Pilot Program***. At this time, BESS have negligible impact to the transmission grid. However, as development continues in the years to come, the impact will have to be taken into consideration in reliability studies. Finally, as high-voltage direct current ("HVDC") technology continues to evolve, the Company will have to continue to evaluate the possibility of utilizing HVDC as generation continues to move away from load centers. However, due to the considerably higher cost of HVDC due to the cable and the alternating current / direct current ("AC/DC") converter stations, this technology will have to continue to be evaluated.

The Company intends to rigorously continue to study each of the technologies above and others yet to come to assure that it can deliver safe, reliable, and affordable power to customers.

Chapter 8: Distribution

The Company's obligation to provide safe and reliable service carries on as the Company transitions toward a cleaner energy future. In fact, providing reliable and resilient service becomes inherently more important during this transition when availability of extensive DERs and expanding electrification are added essentials. As the distribution grid evolves to support a more dynamic energy system, the Company must continuously identify new scenarios and solutions to ensure safe and reliable service. Those solutions will likely include emerging technologies, such as a comprehensive distributed energy resource management system and customer-owned assets leveraged for grid support as non-wires alternatives. Regardless of which solutions are implemented, a robust and secure telecommunication infrastructure platform that provides real-time situational awareness and supports analysis and control of grid components will be essential for an adaptable and responsive distribution grid.

This chapter provides an overview of the distribution planning process and an overview of current initiatives related to the distribution grid.

8.1 Distribution Planning

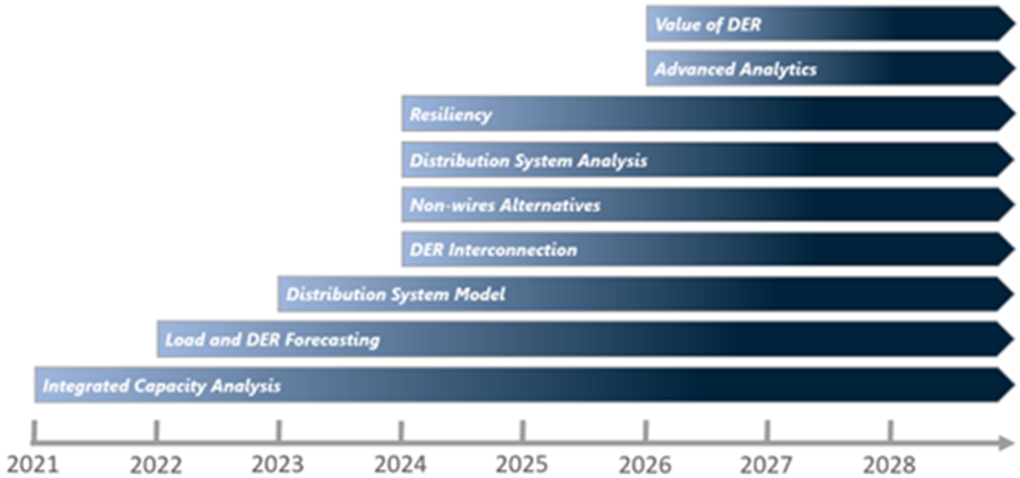
Fundamental changes in the energy industry have driven not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs.

In 2019, the Company presented a white paper that provided a conceptual first look at its transition toward integrated distribution planning ("IDP"). The Company defines integrated distribution planning as a consolidated process to address the capacity, performance, reliability, resilience, and DER integration needs of the distribution grid. The white paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution grid. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including successes related to people, such as the centralization of its organizational structure such that one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments; technologies, primarily through development and implementation of Grid Transformation Plan investments; and processes, such as the development of an initial forecast of DERs by feeder and publications of hosting capacity maps for different types of DERs.

In 2021, the Company noted its continued work on a roadmap for IDP that adds tangible goals and timeframes to IDP maturity and stated its intention to present that roadmap in 2023. The Company's current IDP roadmap is attached as Appendix 8A to this document (the "2023 IDP Roadmap" or the "Roadmap"). The Roadmap presents tangible goals for the components of IDP on which the Company plans to focus in the near term. Figure 8.1.1 provides a visual representation of the Roadmap.

Figure 8.1.1: 2023 IDP Roadmap



The IDP concept is not static, and further changes are expected in the next decade. But the 2023 IDP Roadmap sets the Company on a trajectory to give higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements, while balancing the resources required to implement these components and the interdependencies among many of the components.

8.2 Existing Distribution Facilities

The Company's existing distribution grid in Virginia consists of more than 54,000 miles of overhead and underground cable, and over 400 substations operating at distribution voltage levels ranging from 4 kV to 46 kV. The distribution grid utilizes a variety of devices for functions, from voltage control to power flow management, and relies on multiple operating systems for various functions, from customer billing to outage management.

Appendix B of the executive summary of the Grid Transformation Plan filed in Case No. PUR-2023-00051 provided a detailed description of the Company's existing distribution grid.

8.3 Grid Transformation Plan

The Grid Transformation Plan is the Company's comprehensive plan to transform its electric distribution grid to facilitate the integration of DERs, to enhance grid reliability and security, and to improve the customer experience.

In Phases I and II of the Grid Transformation Plan, which generally covers investments in grid transformation projects between 2019 and 2023, the Company pursued projects that are foundational to the vital objectives of grid transformation. From these initial investments the Company has seen notable successes that have a direct and positive effect on its customers. The Company has deployed AMI to nearly three-quarters of its customers in Virginia, enabling these customers to take control of their energy usage with the granular data that smart meters provide. The Company's new customer information platform ("CIP") went live in April 2023, enabling the systems needed to modernize the customer relationship. The Company has enhanced grid reliability through multiple grid transformation projects, providing a direct benefit to customers and improving the availability of the grid for DERs. And the Company has facilitated the integration of DERs, for example, through the launch of two hosting capacity tools that provide guidance to customers and developers about siting clean energy installations and through its rebate program for the installation of smart charging infrastructure for EVs.

In Phase III, which is currently pending before the SCC in Case No. PUR-2023-00051, the Company seeks to continue its work on approved projects toward the objectives of grid transformation based on the same need that has been shown in prior proceedings. Specifically, the Company seeks to complete the deployment of two foundational GT Plan investments—AMI and the CIP. The Company also seeks to continue its three grid infrastructure projects approved by the SCC in prior phases—mainfeeder hardening, targeted corridor improvement, and voltage island mitigation—along with three of its previously approved grid technologies projects—a DER management system, voltage optimization enablement, and substation technology deployment. Together, these investments will continue to enhance grid reliability and to facilitate the integration of DERs. Finally, the Company seeks to continue investing in enhanced telecommunications and physical substation security, as well as investments in cyber security and customer education as needed to support other proposed projects. Phase III also requests approval of two new projects. First, the Company proposes to deploy a new outage management system to replace an outdated operating system that cannot accommodate the complexity that a modern distribution grid requires. Second, the Company seeks approval of a process to evaluate energy storage systems as non-wires alternatives to traditional distribution investments. This process will enable the Company to gain experience with this integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with non-wires alternatives and that may result in the integration of energy storage systems that can dynamically respond to changing grid conditions.

Overall, the Grid Transformation Plan represents the optimal package to facilitate the integration of DERs while maintaining and enhancing reliable and secure electric service. Achieving these objections is vital to the clean energy goals discussed in this 2023 Plan.

8.4 Strategic Undergrounding Program

The Company is continuing the SUP, which is in its seventh year. Originally conceived as a 4,000-mile program in 2014, the Company has converted approximately 1,888 miles of outage-prone overhead tap lines as of December 31, 2022. A legislative sunset clause currently requires the SUP to conclude in 2028. More details on the SUP are available in the Company's annual filings with the SCC, which specify the miles of tap lines converted and their locations, tap line reliability performance pre- and post-conversion, and system-wide reliability statistics.

Both local and system-wide benefits are key aspects of the SUP. Specifically, the SUP was designed to shorten restoration times in severe weather events by reducing the number of labor-intensive work locations associated with outage-prone single-phase overhead tap lines, especially those behind homes with significant tree coverage. By converting those tap lines to underground, directly served customers will either see a shorter outage or no outage. Perhaps more importantly, this enables crew redeployment to other outage locations, allowing a faster recovery after severe weather events for the benefit of all customers. The SUP remains the most effective and comprehensive solution for eliminating work associated with systemic tap line outages and is complemented by the mainfeeder hardening program in the Grid Transformation Plan, which targets mainfeeders serving customers with the poorest reliability.

8.5 Battery Storage Pilot Program

Specific to the distribution grid, the Company is currently studying the use of battery energy storage systems on its distribution grid through the pilot program established by the GTSA. Two BESS came online on the distribution grid in 2022:

- BESS-1, a 2 MW/4 MWh AC lithium-ion BESS, that is studying the prevention of solar backfeeding onto the transmission grid at a substation located in New Kent County; and
- BESS-2, a 2 MW/4 MWh AC lithium-ion BESS, that is studying batteries as a non-wires alternative to reduce transformer loading at a substation located in Hanover County.

The Company also deployed a lithium-ion BESS at its Scott Solar Facility to study solar plus storage.

The Company filed its first annual report on the pilot program with the SCC on March 31, 2023, in Case No. PUR-2019-00124, including lessons learned from constructing these pilot BESS. As to the two distribution BESS, throughout 2022, BESS-1 showed excellent progress towards meeting its objectives, with initial data analysis indicating that both transformer load tap changer operations and total backfeed have been reduced. Initial results are also very promising for BESS-2, with 18% percent of the exported energy occurring during the two highest load hours of each day on the associated transformer and 39% occurring during the four highest load hours of each day.

These BESS provide the Company the opportunity to study important statutory objectives, and the information and experience gained from each will provide valuable insight and experience toward deployment of BESS in the future. The Company continues to explore additional unique energy storage use cases for future consideration within the battery storage pilot program.

8.6 Electric School Bus Program

The Company's Electric School Bus Program combines the Company's efforts with energy storage technologies and electric vehicles, while at the same time assisting customers' decarbonization efforts. In addition to reducing the carbon footprint of the Commonwealth and improving air quality for students, the batteries in electric school buses can be used to increase the stability and reliability of the grid and can help to facilitate the integration of renewable energy resources such as solar and wind onto the distribution grid. In Phase I of this Program, the Company supported 15 localities and 50 electric school buses. The Company is also supporting localities that receive Virginia Department of Environmental Quality Clean School Bus grants, American Recovery Act Electric School Bus rebates, and EPA Clean School Bus rebates.

The Electric School Bus Program, coupled with a modernized grid, will allow the Company to gain understanding and knowledge regarding strategic deployment of EVs as resources for the benefit of customers and the grid.

8.7 Rural Broadband Program

Originally a pilot program, the rural broadband program is now a permanent, innovative approach to install middle-mile fiber to help achieve universal broadband access across the Commonwealth.

The Company is leveraging the telecommunications infrastructure deployed as part of the Grid Transformation Plan by using a portion of the fiber capacity to meet its own distribution grid needs and then leasing another portion to an internet service provider. By utilizing the telecommunication infrastructure for both operational needs and broadband access, the Company can reduce broadband deployment costs for internet service providers, enabling these providers to deliver high-speed internet access to unserved residences and business.

The Company currently has agreements with over 30 counties to reach unserved areas through partnerships with five internet service providers, including All Points Broadband, RURALBAND, EMPOWER Broadband, Firefly Fiber Broadband, and BARC Connects. The middle-mile project in Surry County is complete and RURALBAND is actively serving Surry County residents. Projects are underway (either in development or under construction) in Botetourt, Stafford, Westmoreland, Richmond, Northumberland, King George, Lancaster, King William, Louisa, Appomattox, Augusta, Loudoun, Culpeper, Fauquier, Rockingham, Hanover, Middlesex, Sussex, Dinwiddie, Albemarle, Buckingham, Cumberland, Fluvanna, Goochland, Nelson, Powhatan, Brunswick, Halifax, and Mecklenburg counties.

As of March 31, 2023, approximately 271 miles of fiber have been installed as part of the Rural Broadband Program, with approximately 2,500 additional miles planned in the remainder of 2023 and beyond.

Chapter 9: Other Information

This chapter provides other information in response to specific SCC or NCUC requirements.

9.1 Environmental Justice

The Virginia Environmental Justice Act ("VEJA") sets the policy of Virginia to promote environmental justice, ensuring the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy. North Carolina's Executive Order No. 246 directs agencies to elevate the consideration of environmental justice, including by identifying an agency point person for environmental justice efforts and by developing a public participation plan to ensure the public is meaningfully engaged in government decision-making.

The transition to a clean energy future requires substantial development of new infrastructure, which has the potential to affect surrounding communities. Recently published draft environmental justice guidance from the Virginia Department of Environmental Quality concluded that applying VEJA definitions results in 53% of the total geographic area and 59% of the population of Virginia meeting the definition of an environmental justice community. The draft guidance also outlined a process by which new projects must be evaluated for environmental justice considerations. The Company looks forward to engaging in the guidance development process as it is finalized.

Dominion Energy and the Company are committed to ensuring that all communities have a meaningful voice in planning and development processes. In cases where a community meets the definition of an environmental justice community, the Company's approach to environmental justice requires consideration of proactive community engagement strategies to ensure that all people have an opportunity to participate meaningfully in the decision-making process. This means providing information in an accessible way, providing opportunities for community members to voice their concerns and provide input, and that such concerns and input are appropriately responded to and that the Company works to minimize or mitigate any disproportionate impacts.

The Company believes that consistent with the mandates and goals of the VCEA and North Carolina Executive Order No. 246, as well as federally developed environmental justice policy, environmental justice is best evaluated and carried out on a case-by-case basis, informed by the location of the project in question and project-specific characteristics. The Company has established an environmental justice review process for evaluating its specific projects and programs that implicate environmental justice consistent with relevant laws and regulations, as well as previously developed EPA guidance, and currently accepted best practices. Based on this, the Company presents the results of these project-specific review processes in the relevant proceedings before the SCC, such as in its applications to construct new generating facilities or new transmission lines and will do so as appropriate in relevant proceedings before the NCUC.

9.2 Customer Education

The Company is committed to improving the customer experience. Key to achieving this goal is educating customers about their energy consumption and how to manage their costs, and empowering customers to take advantage of the numerous enhanced customer capabilities enabled by the Grid Transformation Plan and other initiatives.

The Company's customer education initiatives include providing demand and energy usage information, educational opportunities, and online customer support options to assist customers in managing their energy consumption and taking advantage of new incentives and offerings. The educational initiatives discussed below apply to the Company's customers in both Virginia and North Carolina.

Website and Supporting Print Collateral

The Dominion Energy website—https://www.dominionenergy.com—is a main hub for public education. The Company offers program- and project-specific information, factsheets, brochures, videos, and other supporting documents to provide background and updates on the benefits and enhanced capabilities associated with a variety of investments and initiatives. These include, but are not limited to, approved elements of the Grid Transformation Plan, major infrastructure projects, and new offerings such as rates, tools, and mobile apps as they become available.

Social Media

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 also manages pages on YouTube® and Instagram for further outreach to the general public, residential customers, and business customers. LinkedIn is leveraged for reaching commercial and industrial customers.

The Company's Twitter® account is available online at: https://twitter.com/dominionenergy.
The Company's Facebook® account is available online at:
https://www.facebook.com/dominionenergy.
The Company's YouTube® account is available online at
https://www.youtube.com/user/DomCorpComm.
The Company's Instagram account is available online at
https://www.instagram.com/dominionenergy/.
The Company's LinkedIn account is available online at
https://www.linkedin.com/company/dominionenergy/.

News Releases

The Company prepares news releases and reports on the latest developments regarding its customer-facing initiatives and provides updates on Company offerings and recommendations for saving energy as new information and programs become available. Current and archived news releases can be viewed at: https://news.dominionenergy.com/news.

Customer Information Platform

The customer information platform—approved by the SCC as part of the Grid Transformation Plan—will enable the Company to provide customers with better information. For example, customers will be able to utilize various notification, billing, and pay options to more easily monitor usage and to take advantage of new rate structures and rate comparison tools. The implementation of the customer information system and customer portals, both of which were components of the customer information platform, were completed in April 2023. Overall, with the new capabilities and customer functionality within the customer information platform, customers will be in a better position to save time and money.

Energy Conservation Programs

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. Dozens of programs are featured on the website and include eligibility guidelines, program details, steps to enroll, and success stories, as well as contact information to speak with program specialists. Through consumer education using a variety of channels to reach multiple customer classes, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina.

Online Energy Calculators

The Company is committed to helping customers save on their energy bills and provides saving tips and a "Lower My Bill Guide" on the Company website. Home and business energy calculators are provided as well 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. For customers considering the environmental impact of transportation choices, a calculator is offered to compare emissions and cost savings of cars side-by-side with more efficient hybrid or all-electric vehicles. 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

The Company conducts outreach seminars and speaking engagements in order to share relevant energy conservation program information to both residential and commercial audiences. The Company also participates in various trade shows and exhibits at energy-related events to educate customers on the Company's programs and inform customers and communities about the importance of implementing energy-saving measures in homes and businesses and taking advantage of new rates and offerings as they become available. 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. Additional partnerships with the educational community are offered through mentoring initiatives, philanthropic support, and other means to strengthen science, technology, engineering, and mathematics competitiveness in an effort help prepare students for tomorrow's workplace. Information on educational grants, scholarships, and programs for teachers and students is available on the Company's website at:
https://www.dominionenergy.com/our-company/customers-and-community/educational-programs.

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 lesson plans for use at home and in classrooms, 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. Since 2007, more than 600,000 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 1,500 acres of new forest if all the seedlings are planted and grow to maturity. In 2021, Project Plant It! added a new bee pollinator program, providing wildflower seed packets to teach students about the essential role of bees and other pollinators to the sustainability of the environment. Visit website for more information, https://projectplantit.com/.

9.3 Accelerated Renewable Energy Buyers

In Virginia, the law permits certain customers who certify as ARBs to be exempt from certain costs and benefits related to the mandatory RPS Program. The law defines an ARB as a commercial or industrial customer, irrespective of generation supplier, with an aggregate load over 25 MW in the prior calendar year, that enters arrangements to (i) obtain RECs from RPS eligible sources ("REC-only ARBs") or (ii) bundled capacity, energy, and RECs from solar or wind generation within the PJM region ("Bundled ARBs"). ARBs must be a non-residential customer. Examples of types of customers that qualify as an ARB could be a single industrial facility, a single data center site, a group of commercial office building accounts under the same common parent, or a group of accounts of a retail business under the same common parent. ARBs must certify annually through the processes established by the SCC. Customers that meet the definition of an ARB are not required to certify as ARBs nor are they required to certify up to the full volume of their load—it is the choice and responsibility of the specific customer.

From a ratemaking perspective, customers who certify as ARBs are exempt from paying certain costs, and the remaining costs are allocated to other Company customers. The Company incorporated this aspect of ARBs into the Company Methodology for the Virginia consolidated bill analysis discussed in Section 2.5, ***Virginia Consolidated Bill Analysis***, by removing the actual usage and projected usage from the applicable customer classes for each account that was submitted for certification as an ARB in 2023 according to their submitted exemption status (*i.e.*, full or partial) for the purposes of Virginia RPS Program compliance.

From a planning perspective, ARBs are factored into the Company's planning processes in two ways.

First, all certified ARBs reduce the Company's obligation under the Virginia RPS Program. To the extent a customer certifies as an ARB, that customer's load would be deducted from the Company's RPS Program compliance obligation in proportion to the customer's ARB-certified load. For purposes of this 2023 Plan, the Company used the 2022 production for (i) all Company facilities that are under contract with a customer seeking certification as an ARB in the 2023 certification process, and (ii) all facilities that were submitted by the customer seeking certification as an ARB in the 2023 certification process to calculate the percentage of each customer's load covered by its renewable energy facilities The Company then maintained the calculated percentage to project that customer's load over the 25-year Study Period of this 2023 Plan, which assumes customer growth and that each facility maintains its 2022 production during the life of the contract. For example, if a customer currently is able to certify as an ARB and demonstrated they were able to meet 100% of their 2022 load through qualified renewable energy, the 2023 Plan assumes this customer would continue to meet 100% of their load in the future. The Company repeated this process for each customer seeking certification as ARB.

Second, the capacity of solar or wind resources that Bundled ARBs have under contract offset the development targets for solar and onshore wind established through the VCEA. For purposes of this 2023 Plan, the Company has offset its development targets based on information submitted for the ARB certification process in 2023. The Company updates these offsets annually based on information provided by ARBs during the annual ARB certification process.

Importantly, a customer's status as an ARB does not affect the Company's obligation to meet the electricity supply service needs (*i.e.*, capacity, energy, and ancillary services) of the customer, assuming the customer receives these services from the Company rather than from a competitive service provider. In other words, the Company's load forecast and planning obligations do not change if a portion of forecasted non-residential load increases come from customers who may certify as ARBs. These customers must be provided electric supply service regardless. Accordingly, the Company did not adjust its load forecasts to account for ARBs, except when the forecast was used to estimate the Company's annual compliance obligations under the Virginia RPS Program. That said, the Company has provided sensitivities on Alternative Plan B under different load forecasts to show the effect if the load forecast were to vary for any number of reasons; see Section 2.6, ***Sensitivity Analyses***.

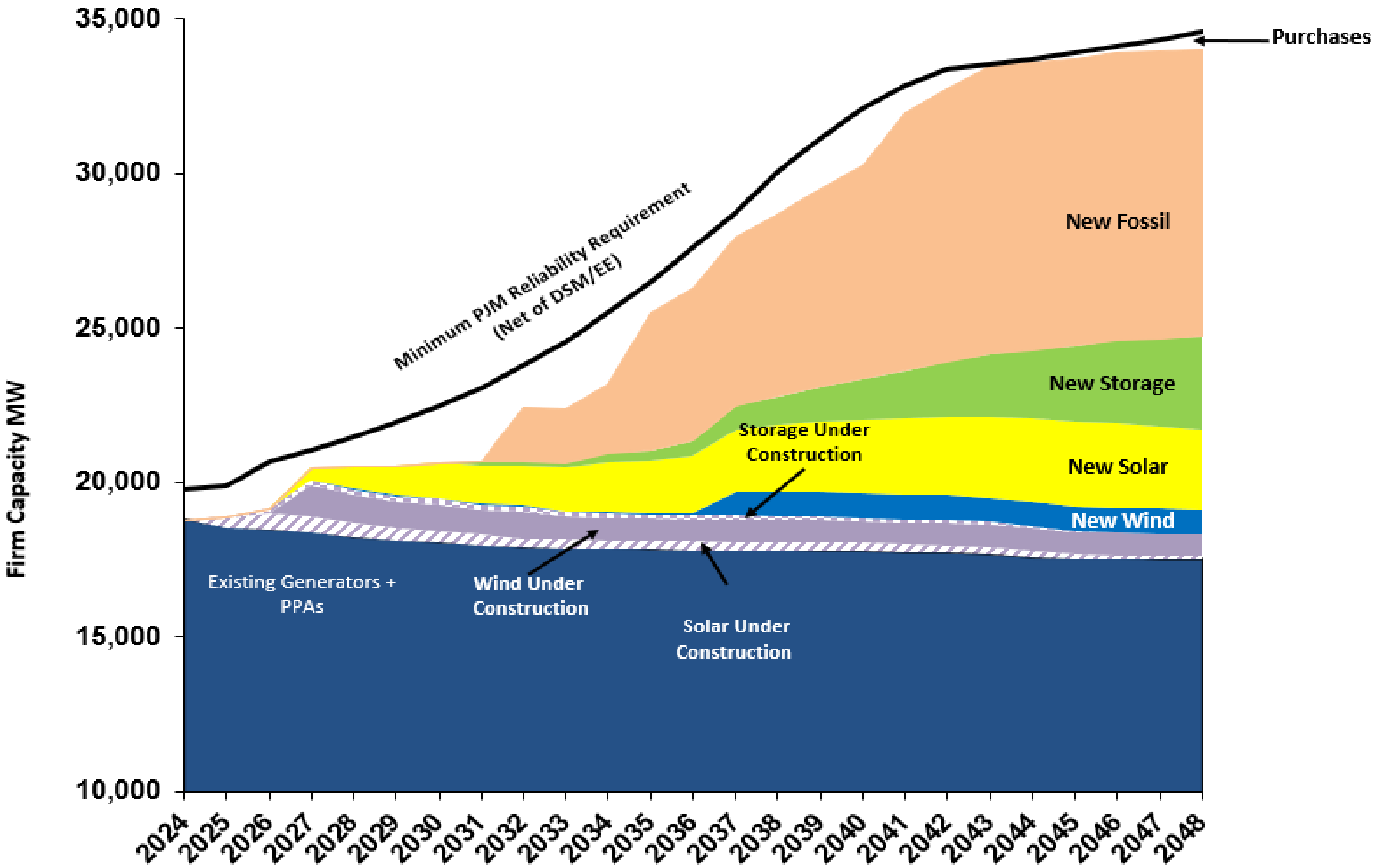
9.4 Economic Development Rates

As of March 2023, the Company has 10 customer locations in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 226 MW. As of March 2023, the Company has one customer in North Carolina receiving service under an economic development rate. The total load associated with this rate is approximately 2 MW.

APPENDICES

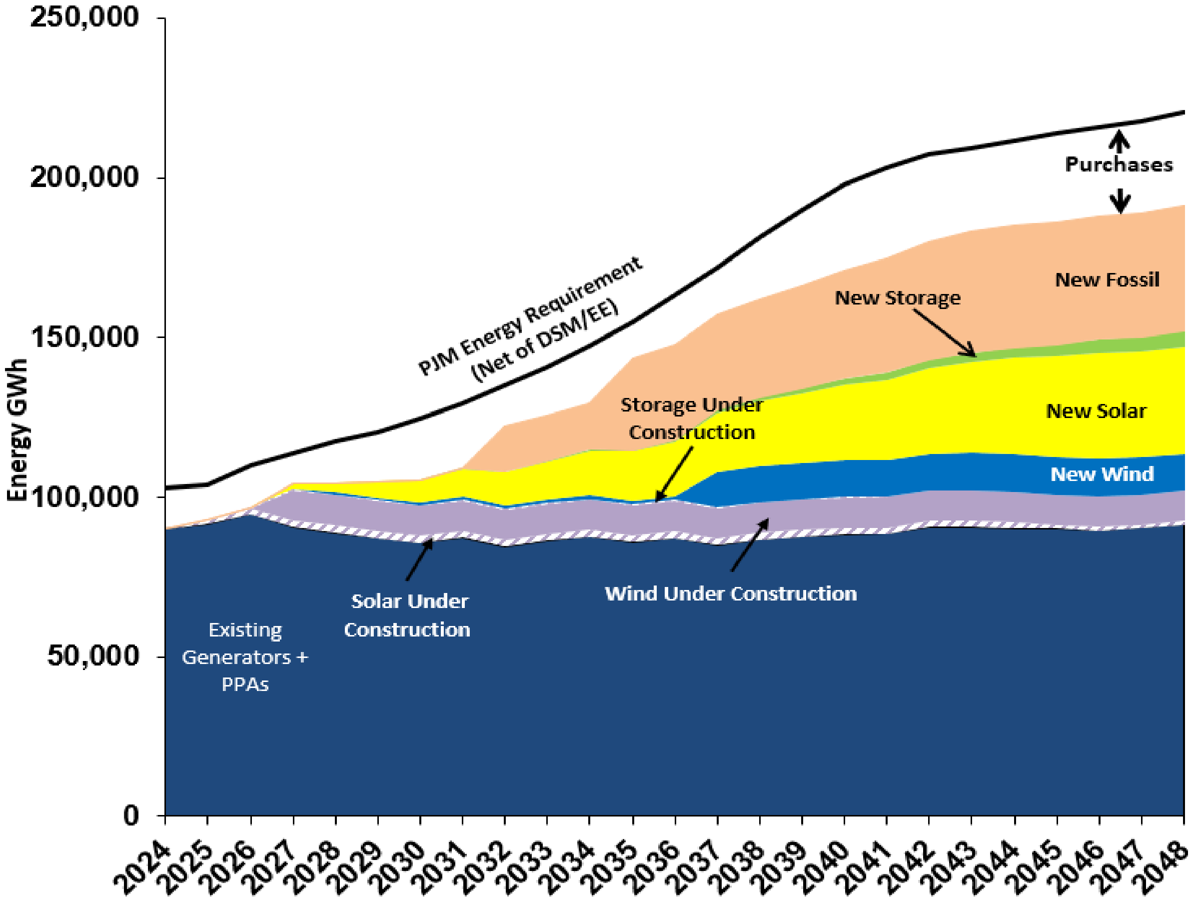
Appendix 2A: Plan A -Summer Capacity, Energy, and RECs

Capacity



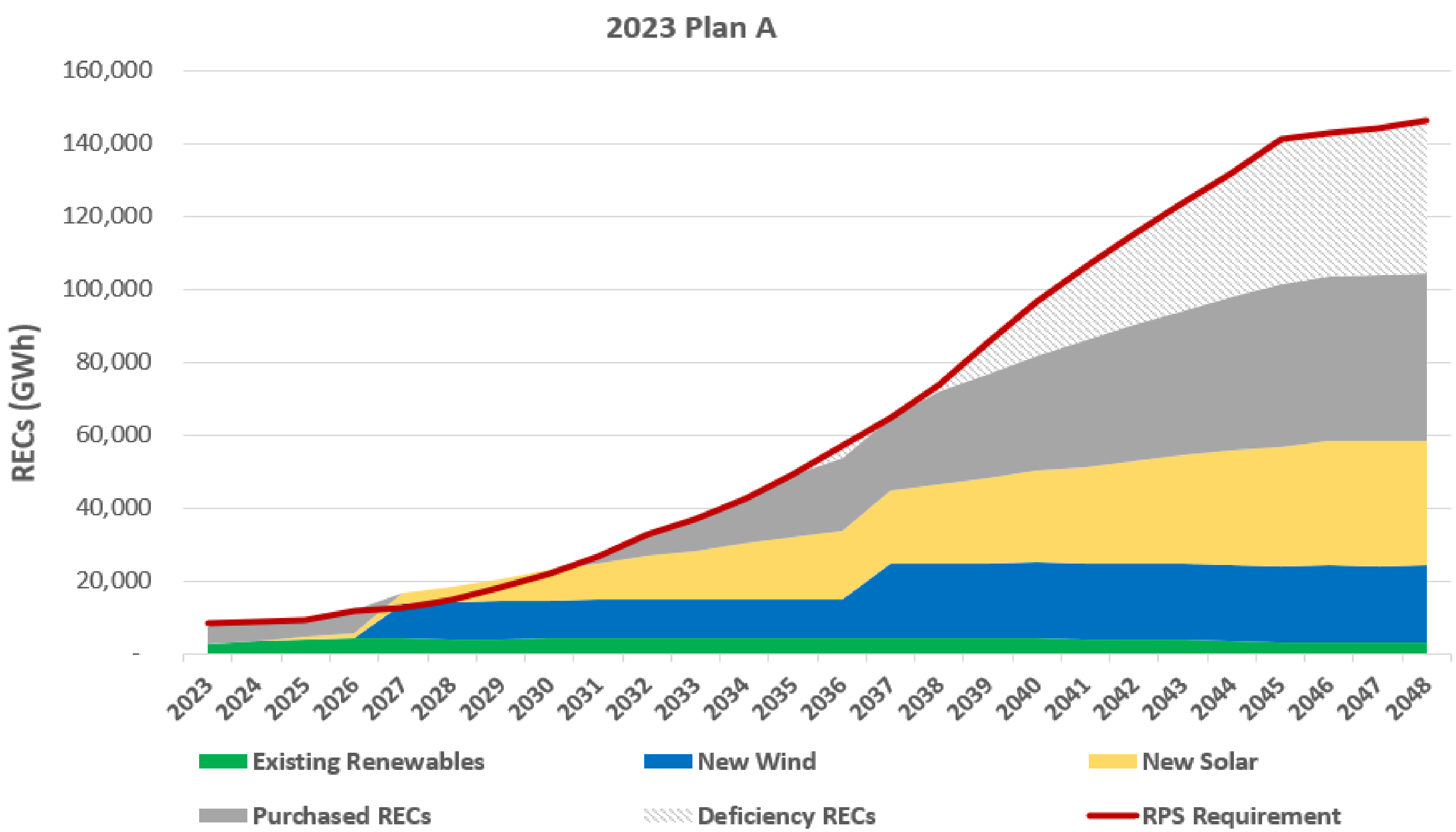
Appendix 2A: Plan A -Summer Capacity, Energy, and RECs

Energy



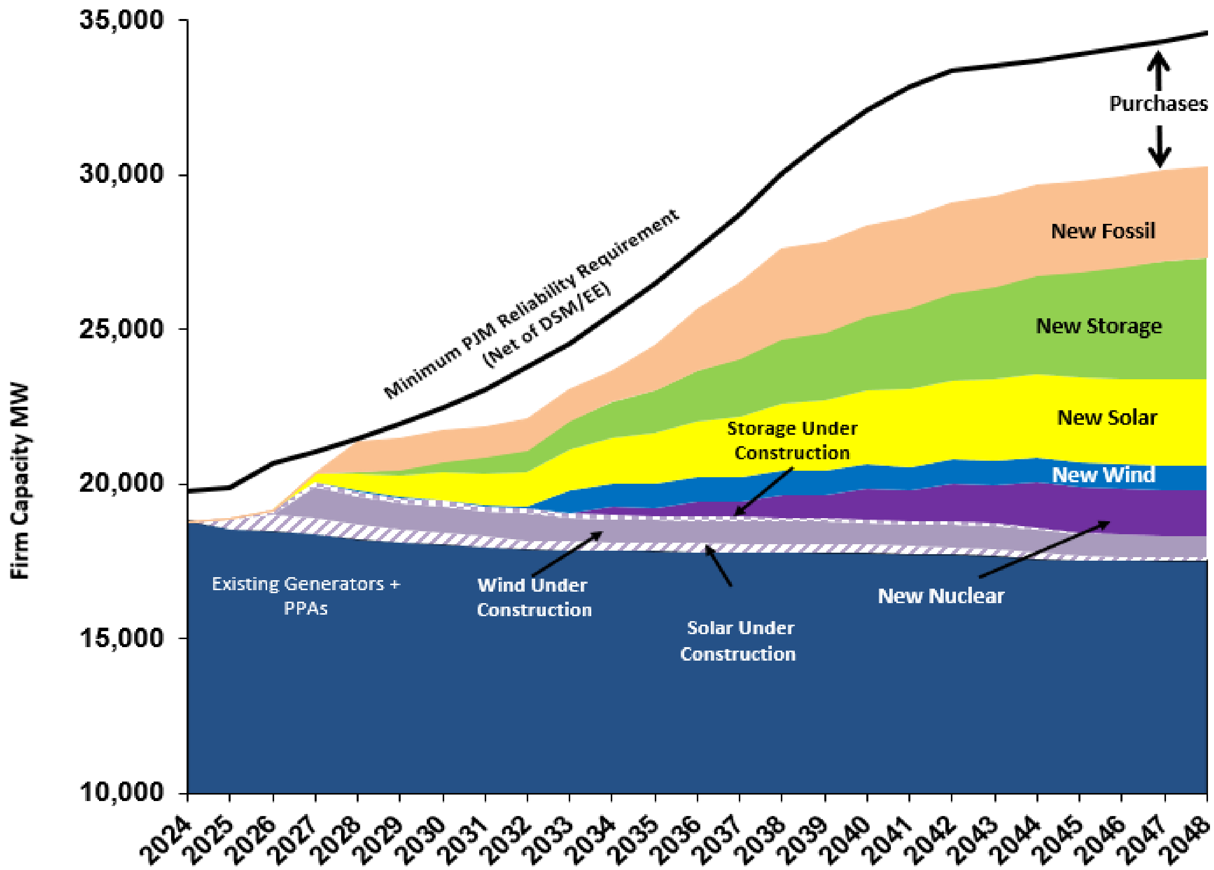
Appendix 2A: Plan A -Summer Capacity, Energy, and RECs

RECs



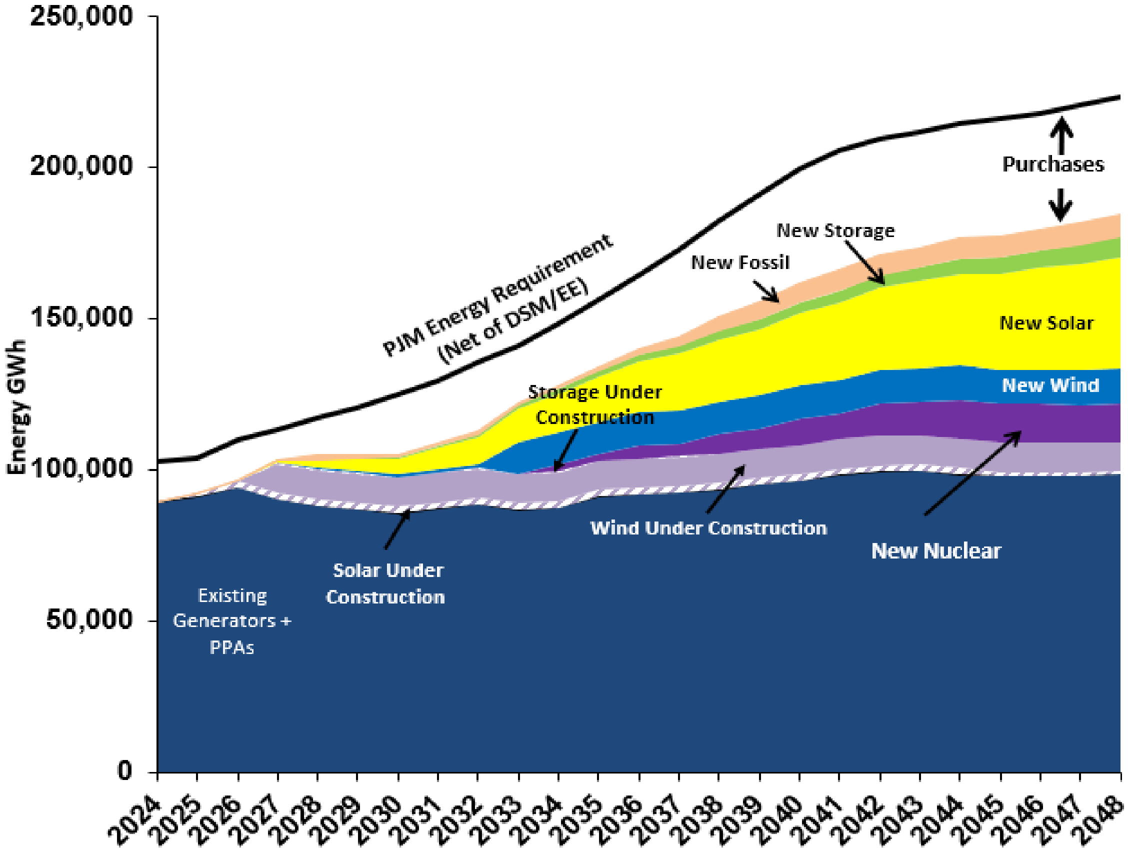
Appendix 2A: Plan B - Summer Capacity, Energy, and RECs

Capacity



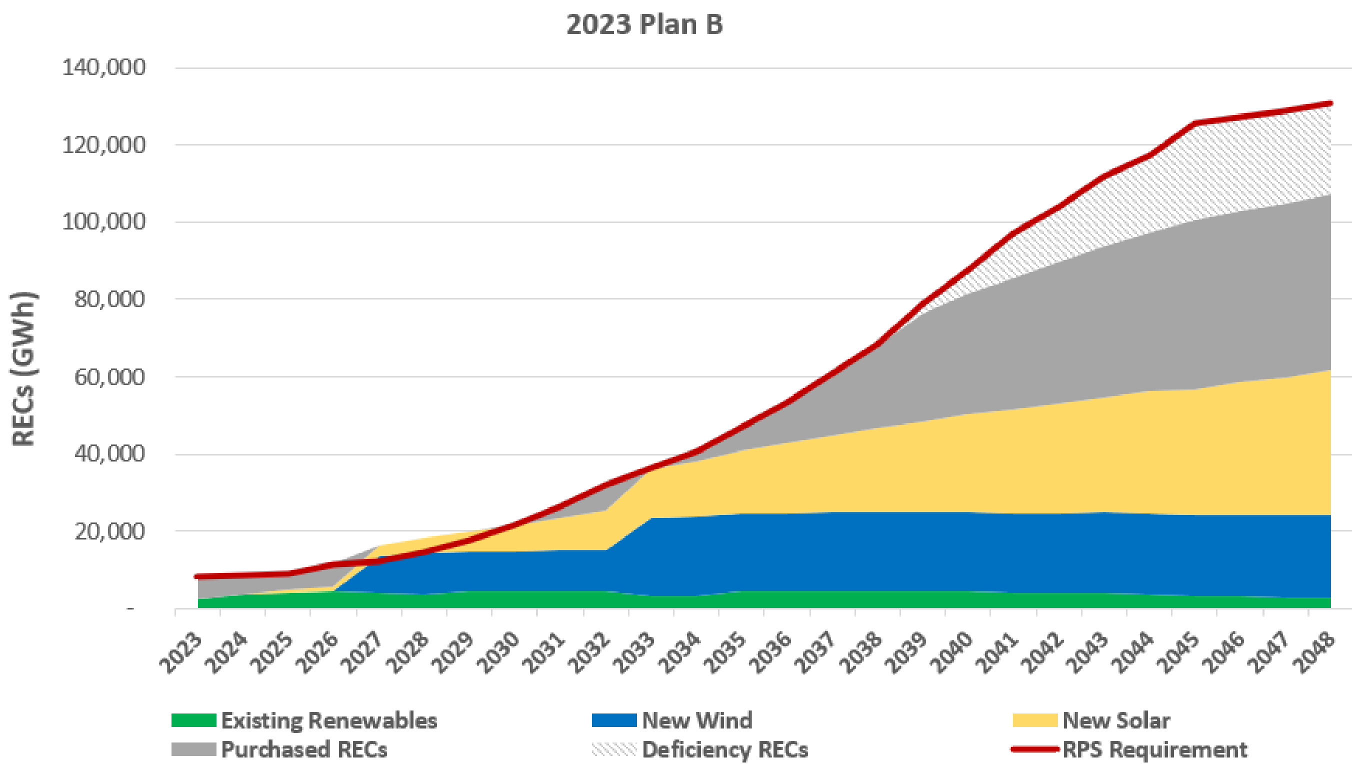
Appendix 2A: Plan B - Summer Capacity, Energy, and RECs

Energy



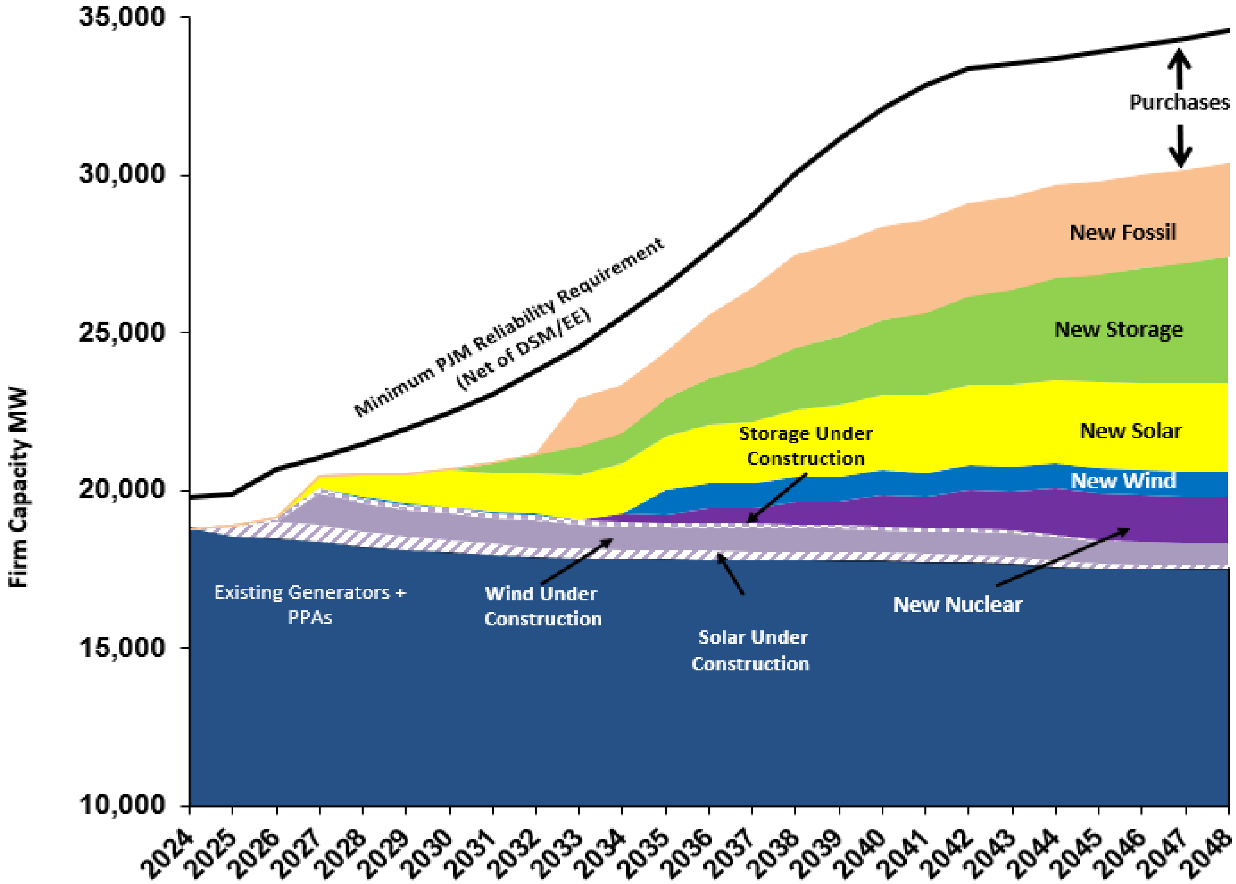
Appendix 2A: Plan B - Summer Capacity, Energy, and RECs

RECs



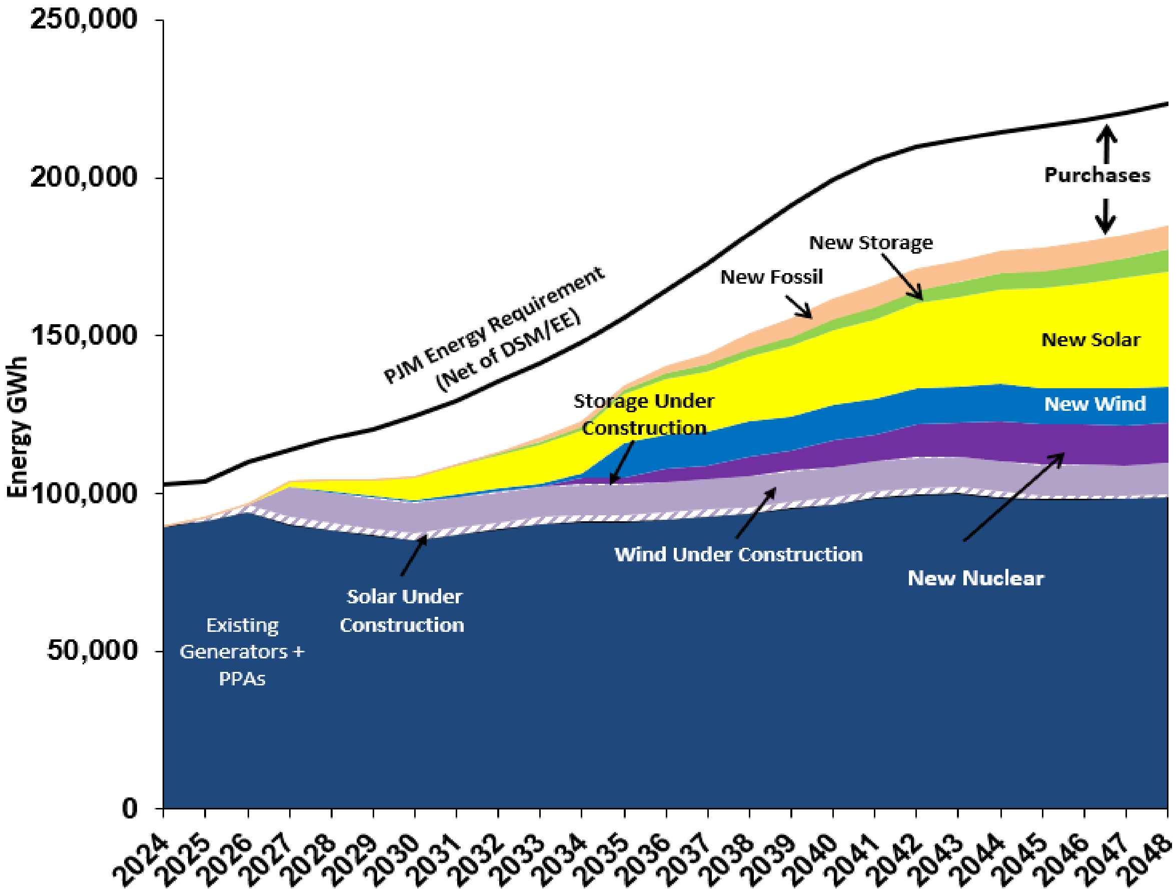
Appendix 2A: Plan C - Summer Capacity, Energy, and RECs

Capacity



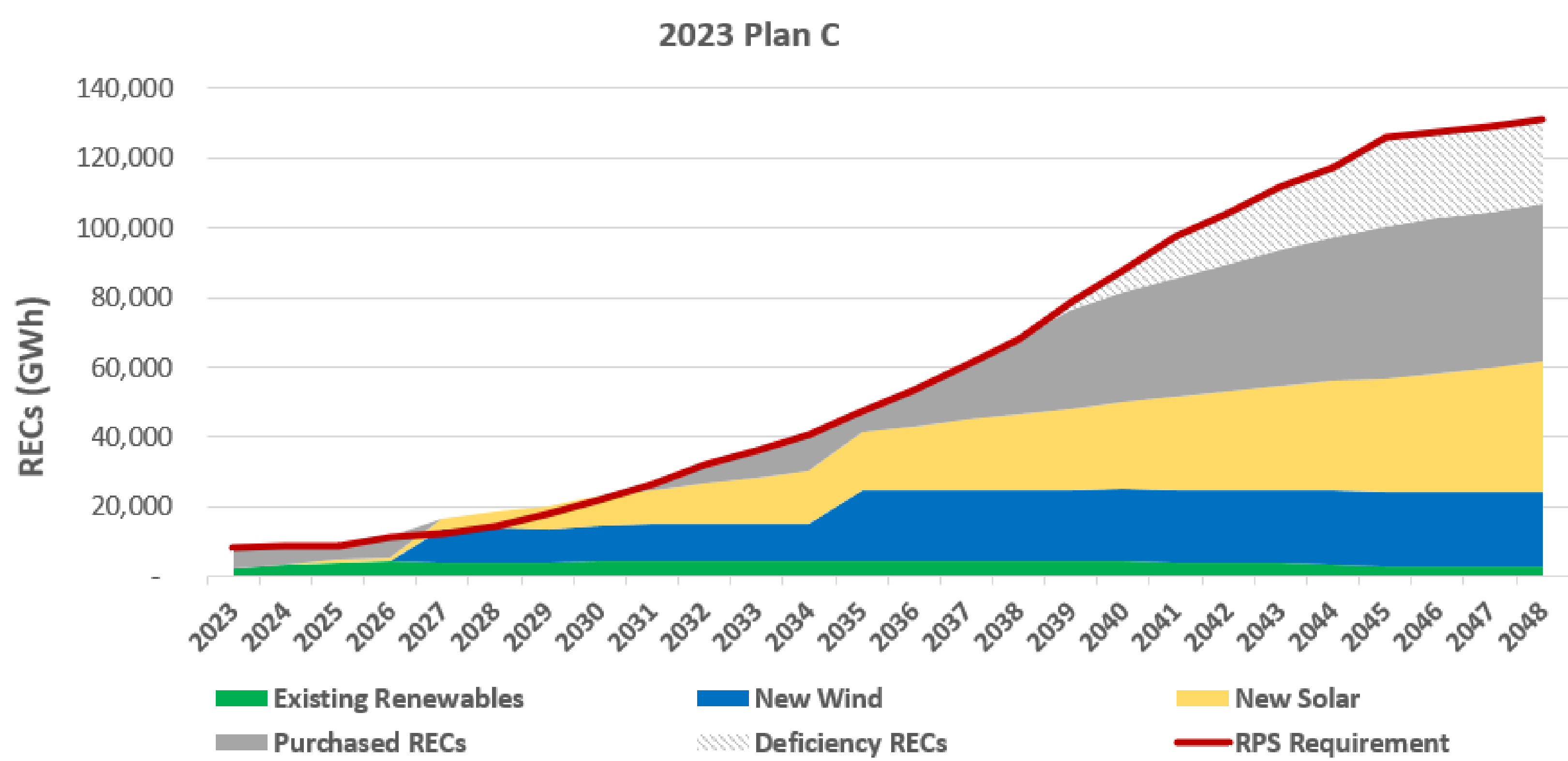
Appendix 2A: Plan C - Summer Capacity, Energy, and RECs

Energy



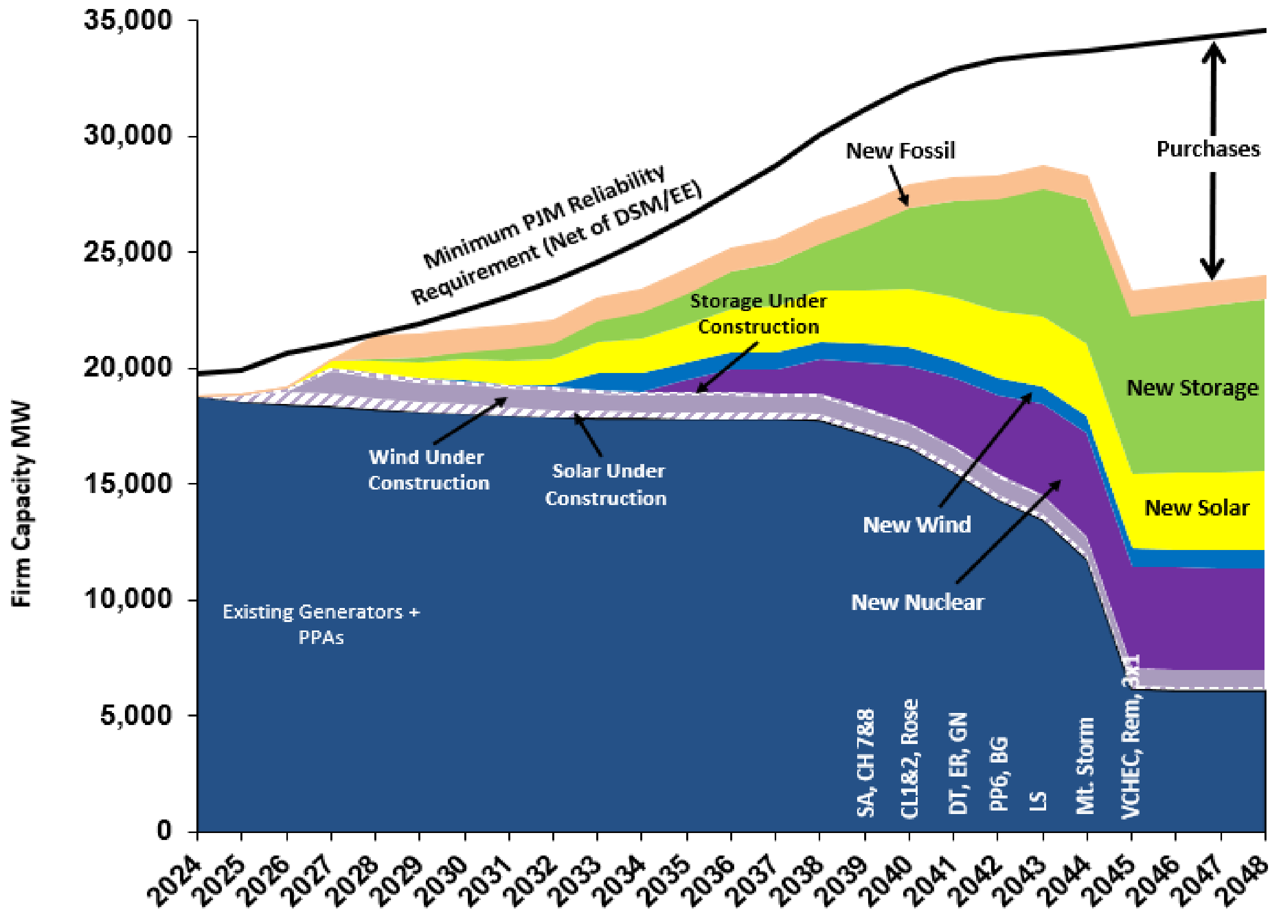
Appendix 2A: Plan C - Summer Capacity, Energy, and RECs

RECs



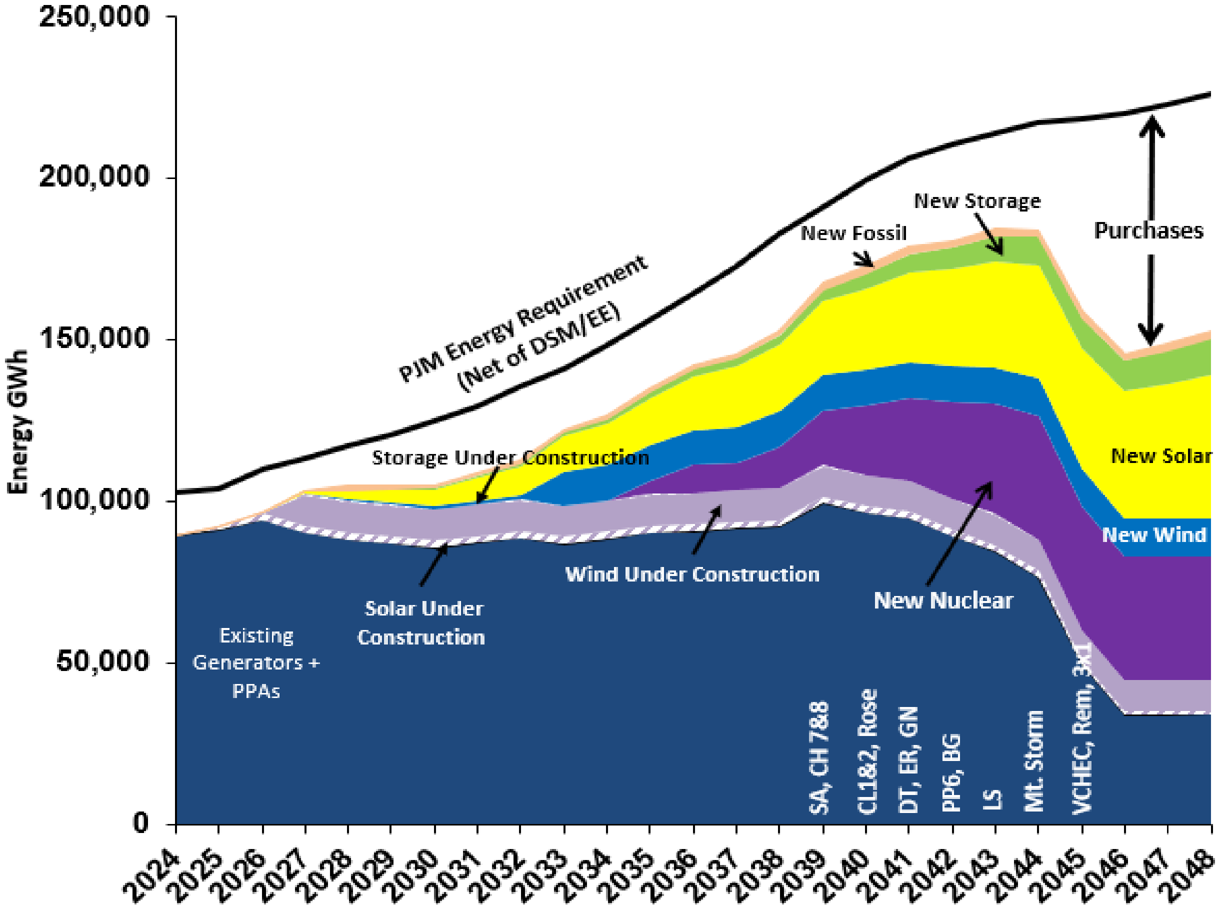
Appendix 2A: Plan D - Summer Capacity, Energy, and RECs

Capacity



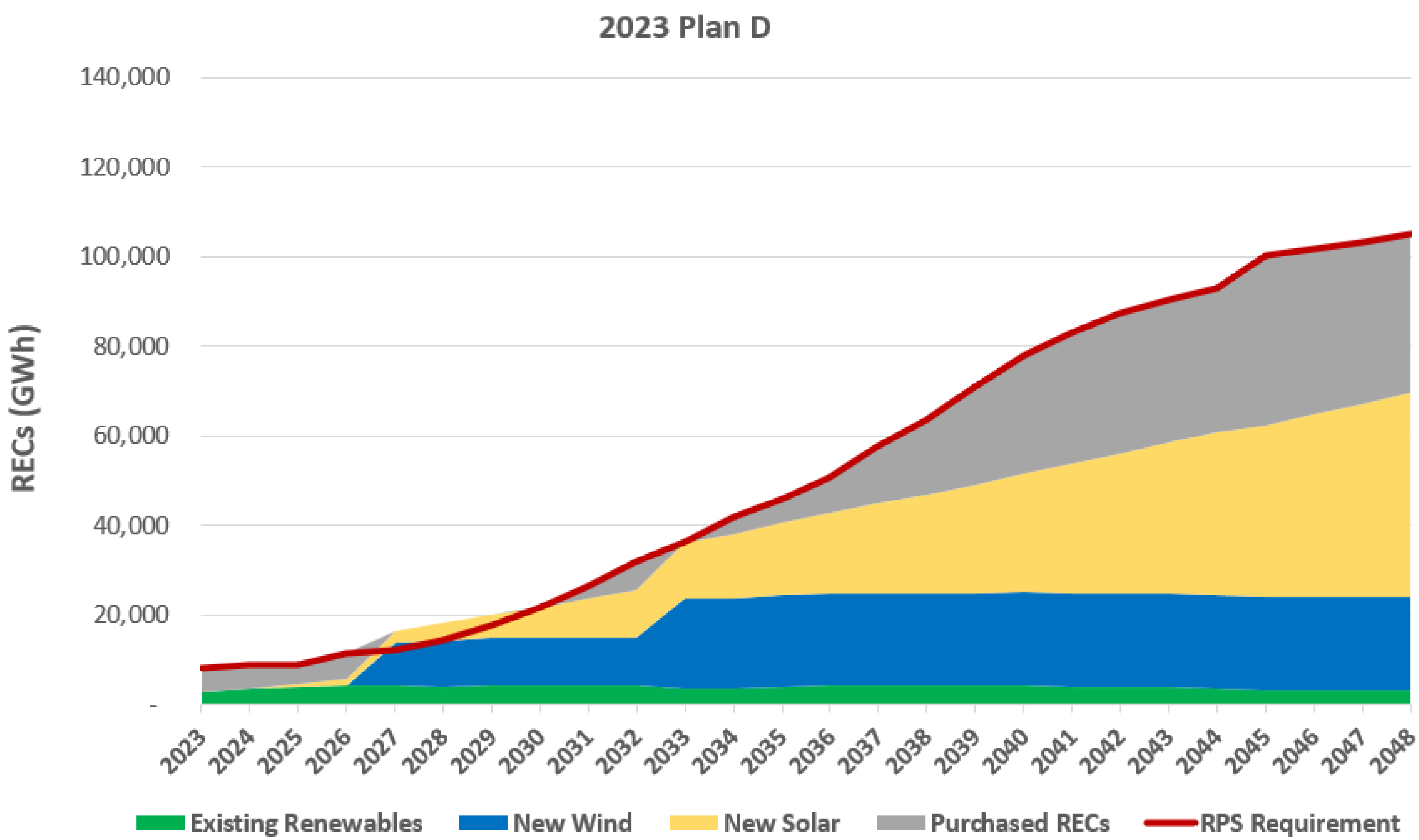
Appendix 2A: Plan D - Summer Capacity, Energy, and RECs

Energy



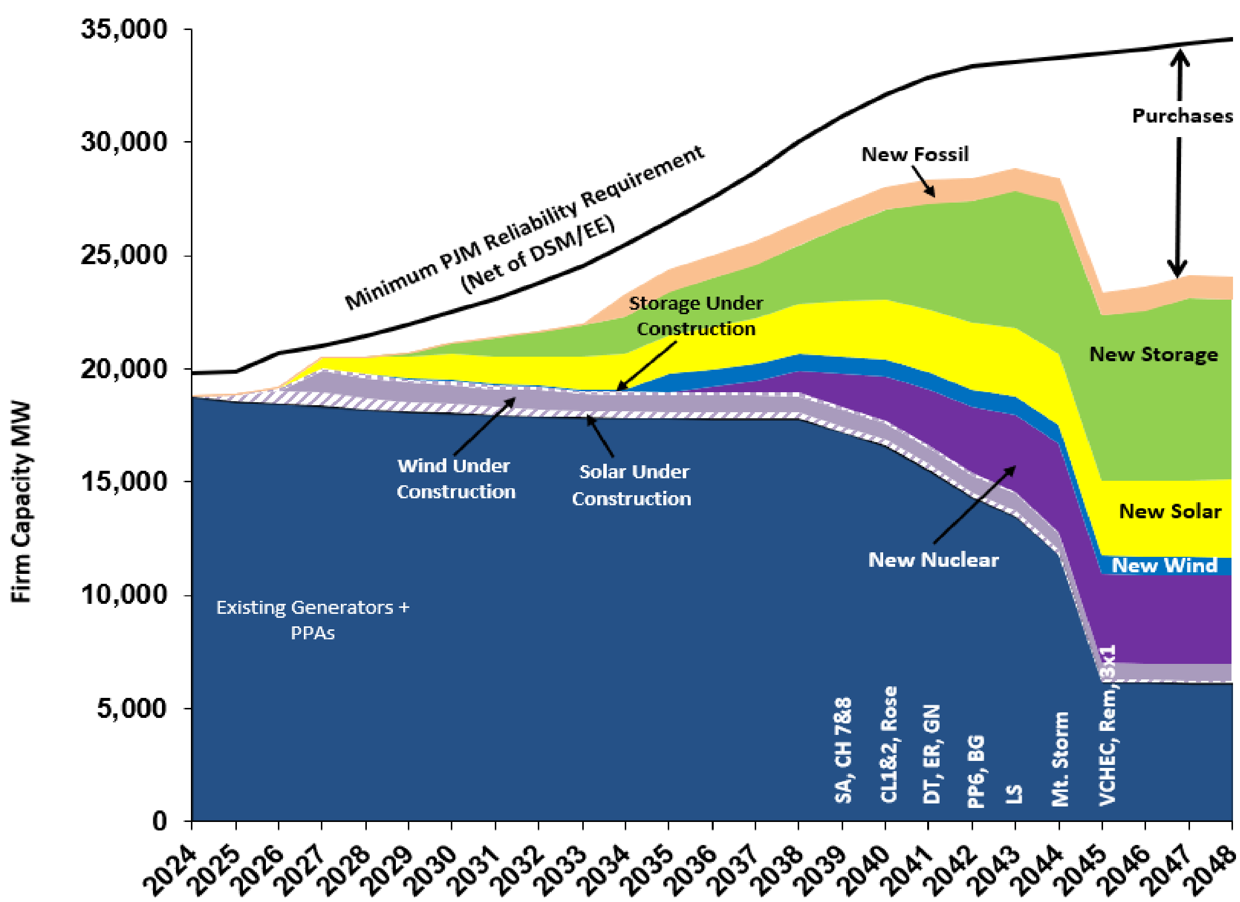
Appendix 2A: Plan D - Summer Capacity, Energy, and RECs

RECs



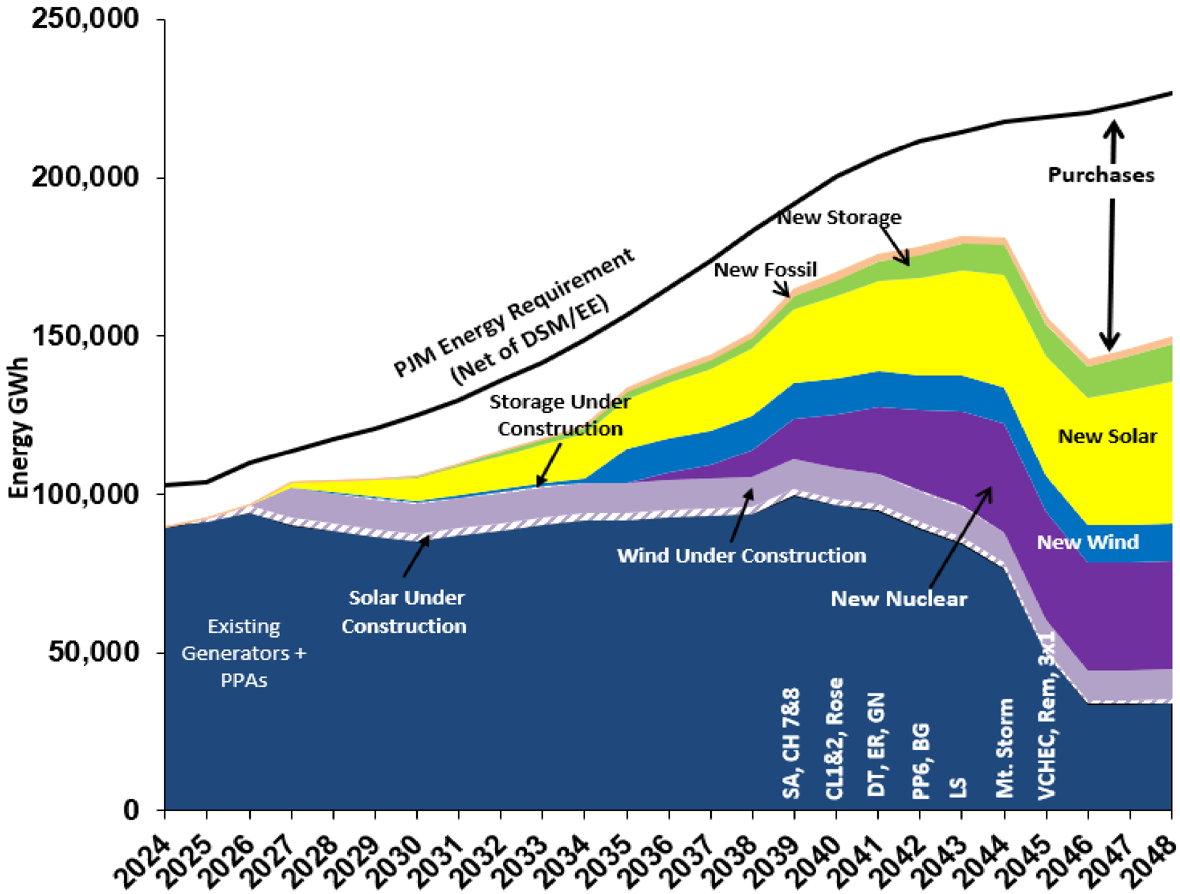
Appendix 2A: Plan E - Summer Capacity, Energy, and RECs

Capacity



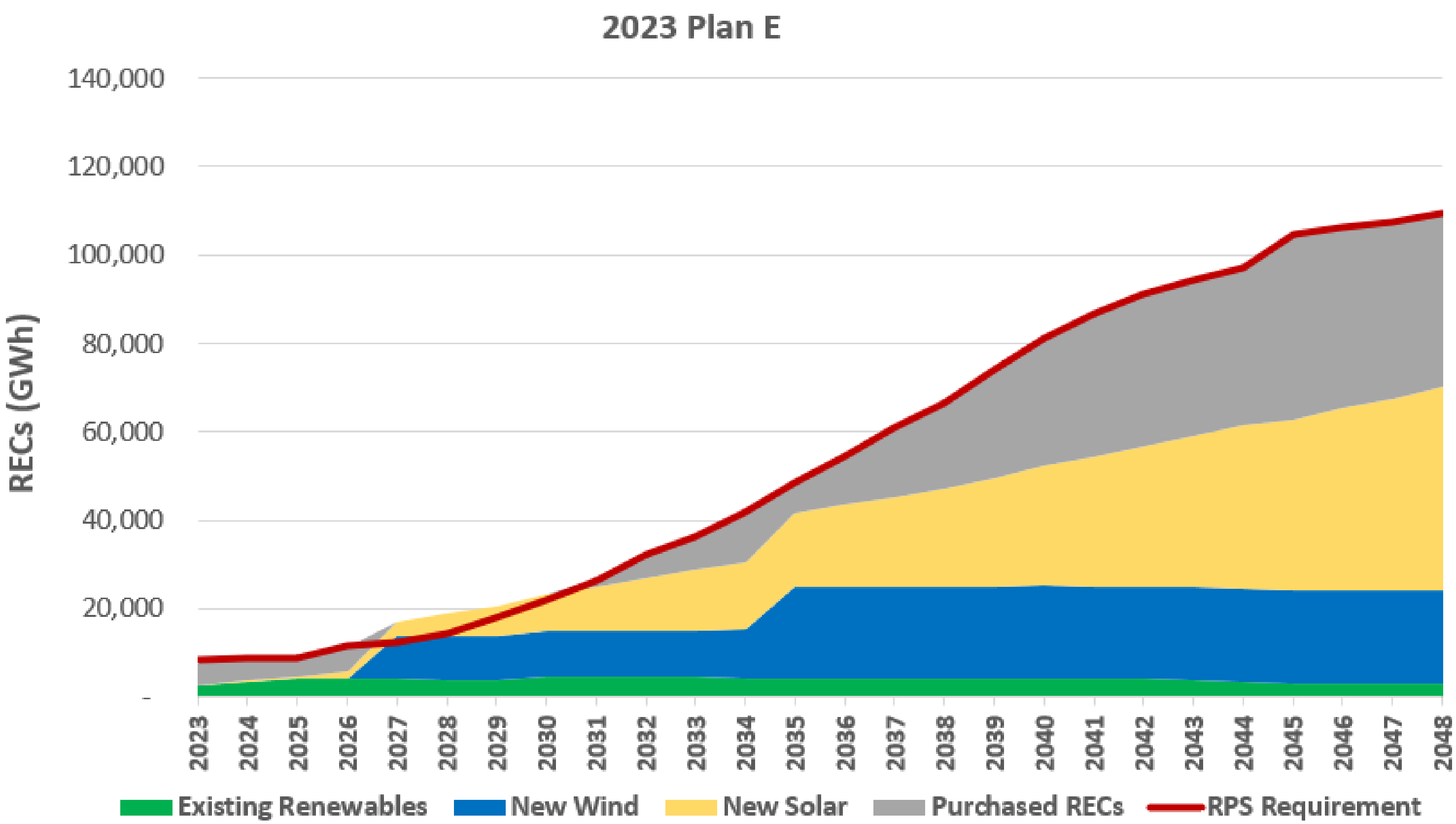
Appendix 2A: Plan E - Summer Capacity, Energy, and RECs

Energy



Appendix 2A: Plan E - Summer Capacity, Energy, and RECs

RECs



Appendix 2B (i-iii): Capacity Information Directed by the SCC

	2023 PJM Load Forecast			
	Coincident Peak (CP)		Non-Coincident Peak (NCP)	
Year	DOM Zone Summer Forecast	LSE Equivalent	DOM Zone Summer Forecast	LSE Equivalent
2023	21,274	16,998	21,920	17,552
2024	22,126	17,266	22,828	17,867
2025	23,058	17,348	23,758	17,948
2026	24,823	18,019	25,568	18,657
2027	26,375	18,341	27,157	19,012
2028	27,906	18,715	28,705	19,400
2029	29,414	19,133	30,216	19,821
2030	30,794	19,622	31,633	20,341
2031	32,276	20,129	33,055	20,796
2032	33,641	20,752	34,465	21,459
2033	34,957	21,415	35,789	22,128
2034	36,221	22,235	36,980	22,886
2035	37,367	23,104	38,115	23,745
2036	38,517	24,059	39,255	24,692
2037	39,690	25,050	40,443	25,695
2038	40,998	26,193	41,741	26,830

Appendix 2B (iv-v) cont.: Capacity Information Directed by the SCC

Unit Name	Nameplate MW
Altavista	71.1
Bath County 1	477.0
Bath County 2	477.0
Bath County 3	477.0
Bath County 4	477.0
Bath County 5	477.0
Bath County 6	477.0
Bear Garden	559.0
Brunswick County	1,472.2
Chesapeake CT 1, 4, 6	51.1
Chesterfield 5	359.0
Chesterfield 6	693.9
Chesterfield 7	219.4
Chesterfield 8	227.2
Clover 1	424.0
Clover 2	424.0
Colonial Trail West	142.4
CVOW	12.0
Darbytown 1	92.1
Darbytown 2	92.1
Darbytown 3	92.1
Darbytown 4	92.1
Elizabeth River 1	129.6
Elizabeth River 2	129.6
Elizabeth River 3	129.6
Gaston 1-4	177.6
Grassfield	20.0
Gordonsville 1	150.2
Gordonsville 2	150.2
Gravel Neck 3	91.9
Gravel Neck 4	91.9
Gravel Neck 5	91.9
Gravel Neck 6	91.9
Gravel Neck GT 1, 2	40.1
Greensville	1,773.3
Hopewell	71.1
Ladysmith 1	178.5
Ladysmith 2	178.5
Ladysmith 3	178.5
Ladysmith 4	178.5
Ladysmith 5	178.5
Lowmoor 1	20.7
Lowmoor 2	20.7
Lowmoor 3	20.7
Lowmoor 4	20.7

Appendix 2B (iv-v) cont.: Capacity Information Directed by the SCC

Unit Name	Nameplate MW
Mt. Storm 1	570.2
Mt. Storm 2	570.2
Mt. Storm 3	522.0
Mt. Storm GT1	18.5
North Anna 1	979.7
North Anna 2	979.7
Northern Neck 1	20.7
Northern Neck 2	20.7
Northern Neck 3	20.7
Northern Neck 4	20.7
Piney Creek	80.0
Possum Point 6	613.0
Possum Point CT 1-6	96.0
Remington 1	178.5
Remington 2	170.0
Remington 3	178.5
Remington 4	178.5
Roanoke Rapids 1-4	100.0
Rosemary	180.0
Sadler Solar	100.0
Scott Solar	17.3
Southampton 1	71.1
Spring Grove	97.9
Stage Coach/Water Strider	80.0
Stratford/Suffolk/White Marsh	15.0
Surry 1	847.5
Surry 2	847.5
Sycamore	42.0
VCHEC	668.0
Warren	1,472.2
Watlington	20.0
Yorktown 3	882.0
Woodland Solar	19.0
Whitehouse Solar	20.0

Appendix 2B (vi): Capacity Information Directed by the SCC

Dominion Energy Virginia
600 East Canal Street
Richmond, VA 23219
www.DominionEnergy.com

February 20, 2020

Mr. David Schweizer, P.E.
Manager, Generation
PJM Interconnection
2750 Monroe Boulevard
Audubon, PA 19403

Dear Mr. Schweizer,

Dominion Energy Virginia is requesting deactivation (retirement) of its Chesterfield 5 & 6 generating units located in Chester, Virginia. Chesterfield units 5 & 6 will be deactivated no later than May 31, 2023. Chesterfield units 5 & 6 have been committed into the RPM capacity market through May 31, 2022.

Dominion is requesting that the existing Capacity Injection Rights (CIR's) be transferred to PJM queue requests AF1-128 and AF1-129. Additionally, it is Dominion's understanding that the CIR's for previously deactivated Chesterfield units 3 & 4 have (or will) be applied to PJM queue request AF1-128. The total quantity of CIR's from deactivation will exceed those of the new requested units.

Dominion has performed financial analyses that show that current and forecasted market revenues do not support the continued operation of these units. Over the course of time the expected requirements or implementation dates for environmental or regulatory regulations may change, as well as significant changes in the energy, ancillary, and capacity markets.

Please call Jeff Currier at 804-273-4269 or Scott Gaskill at 804-273-4438 if you require any additional information.

Sincerely,

Joshua J. Bennett
Vice President Technical Services
Power Generation
Dominion Energy Virginia

December 21, 2022

Generator Deactivations
PJM Interconnection
2750 Monroe Boulevard
Audubon, PA 19403

PJM,

Dominion Energy Virginia is notifying PJM of deactivation (retirement) of its Yorktown 3 generating unit located in Yorktown, Virginia, per the PJM Open Access Transmission Tariff OATT). Yorktown 3 will be deactivated after April 1, 2023, and on or before May 31, 2023. Yorktown 3 has been included in Dominion's FRR capacity plan through May 31, 2025 and will be removed upon deactivation.

Please call Jeff Currier at 804-273-4269 or Jacki Vitiello at 804-317-2971 if you require any additional information.

Sincerely,

Jacqueline Vitiello

Jacqueline R Vitiello
Director, Energy Supply
Dominion Energy Virginia

2750 Monroe Blvd.
Audubon, PA 19403-2497

David W. Souder
Executive Director, System
Planning

March 1, 2023

Jacqueline R Vitiello
Director, Energy Supply
Dominion Energy Virginia
600 Canal Place
Richmond, VA 23219

Re: Deactivation Notice for Yorktown 3 Generating Unit

Dear Ms. Vitiello,

This letter is submitted by PJM Interconnection, L.L.C. ("PJM"), in response to the notice submitted by Dominion Energy Virginia dated December 20, 2022 notifying PJM of the intent to deactivate the following generating unit located in the PJM region effective on May 31, 2023:

- Yorktown 3 Generating Unit

PJM's System Planning Modeling Department and the affected Transmission Owner performed a study of the Transmission System and found reliability concerns associated with generation deliverability resulting from the deactivation of the above listed generating units. However, there are operational measures in place to keep the transmission system reliable.

Therefore, in accordance with Section 113.2 of the PJM Open Access Transmission Tariff (PJM Tariff), this letter serves to notify you that the deactivation of the above listed unit can occur on the requested deactivation date, and should not adversely affect the reliability of the PJM Transmission System. Any revisions to the requested deactivation date shall require the Generator Owner to provide PJM with a revised notice in accordance with section 113.2 of the PJM Tariff.

Please be advised that PJM's deactivation analysis does not supersede any outstanding contractual obligations between the above listed generating unit and any other parties that must be resolved before deactivating these generators.

Also please note that in accordance with the PJM Tariff Part VI, Subpart C, a Generation Owner will lose the Capacity Interconnection Rights associated with a deactivated generating unit one year from the actual Deactivation Date unless the holder of such rights submits a new Generation Interconnection Request within one year after the Deactivation Date.

In addition, if a generating unit is receiving Schedule 2 payments for Reactive Supply and Voltage Control, the generating unit owner must notify PJM in writing when the unit is deactivated. Moreover, in accordance with the requirements of Schedule 2 of the PJM Tariff, the generation unit owner must: (1) submit a filing to the Federal Energy Regulatory Commission ("FERC") to terminate or adjust its cost-based rate schedule to account for the deactivated or transferred unit; or (2) submit an informational filing to the FERC explaining the basis for the decision not to terminate or revise its cost-based rate schedule.

Please contact Augustine Caven (610-666-8200) (Augustine.Caven@pjm.com) in PJM's Infrastructure Coordination Department if you have any questions about the PJM analysis.

Very truly yours,

David W. Souder

David W. Souder,
Executive Director, System Planning

cc:
Joseph Bowring, MMU <Joseph.Bowring@monitoringanalytics.com>
Paul E. Pfeffer <paul.e.pfeffer@dominionenergy.com>
Lisa R. Crabtree <lisa.r.crabtree@dominionenergy.com>
Jeffery E. Currier <jeffrey.currier@dominionenergy.com>
Wesley Walker <wesley.walker@dominionenergy.com>

Appendix 3A – 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 Annual Firm(2)	MW Nameplate
Dulles Tied Solar	VA	Intermittent	Solar	2026	27	100
Sweet Sue Solar	VA	Intermittent	Solar	2026	20	74.76
Bridleton Solar	VA	Intermittent	Solar	2026	5	20
Cerulean Solar	VA	Intermittent	Solar	2026	16	62
Courthouse Solar	VA	Intermittent	Solar	2026	44	167
Ivy Landfill Distributed	VA	Intermittent	Solar	2025	1	3
Racefield Distributed	VA	Intermittent	Solar	2025	1	3
Kings Creek Solar	VA	Intermittent	Solar	2026	5	20
Southern VA Solar	VA	Intermittent	Solar	2025	33	125
Moon Corner Solar	VA	Intermittent	Solar	2026	16	60
North Ridge Solar	VA	Intermittent	Solar	2026	5	20
CVOW - Phase 1 (2587MW)	VA	Intermittent	Wind	2027	793	2587
Dulles Tied Storage	VA	Peak	Grid	2026	44	50
Shands Storage	VA	Peak	Grid	2026	14	15.7

(1) Commercial operation date

(2) Solar firm based on average ELCC value

Appendix 3B – 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.(1)	MW Summer	MW Nameplate
Under Development						
CE-4 Solar	VA	Intermittent	Solar			
CE-4 Distributed Solar	VA	Intermittent	Solar			
Storage	VA	Peak	Grid			
Combustion Turbines	VA	Peak	Gas	2027		

(1) Estimated commercial operation date.

Appendix 3C - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Cemetery Road Sub - 115kV Delivery - DEV	115	Jan-24	VA	5.0
Lockridge - Add Three TX - DEV	230	Jan-24	VA	1.5
Sinai - 115kV Delivery - Add 2nd TX - DEV	115	Feb-24	VA	0.5
Winters Branch 230kV Delivery - Add 4th TX - DEV	230	Mar-24	VA	0.3
Opal 230 kV Delivery - DEV (New)	230	Apr-24	VA	0.8
Techpark Place SUB - New 230kV Delivery - DEV - Engineering Assessment	230	Apr-24	VA	25.0
Quantico Tx 1 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Quantico Tx 2 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Deep Creek Tx 1 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Alexanders Corner Tx 1 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Tunis Tx 2 Replace Ground Switch With Circuit Switcher	115	Apr-24	NC	0.3
Brown Boveri Tx 1 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Brickyard 230kV Delivery - Dominion	230	May-24	VA	6.6
Lincoln Park 230kV Delivery - DEV	230	Jun-24	VA	19.3
230 kV Line Extension Cannon Branch to Winters Branch	230	Jun-24	VA	38.5
Mt Storm Substation GIS	500	Jun-24	VA	69.0
Cloud Sub - 230 kV Delivery (MEC) -Coleman Creek DP - Extend Line #235 Double Circuit Chase City	230	Jun-24	VA	81.0
Easters Sub - 230 kV Delivery (MEC) - Timber DP	230	Jun-24	VA	20.0
EPG - Add 2nd and 3rd TX - DEV	230	Jun-24	VA	1.5
Line #224 Lanexa to Northern Neck Rebuild and second circuit	230	Jun-24	VA	112.2
DTC 230kV Delivery - DEV	230	Jun-24	VA	60.3
City of Franklin P&L DP#4 (Pretlow) - New 115kV Delivery Point	115	Jun-24	VA	1.3
Line #141 Balcony Falls to Skimmer and Line #28 Balcony Falls to Cushaw Rebuild	115	Jun-24	VA	30.9
Line 100 Harrowgate to Locks EOL Partial Rebuild	115	Jun-24	VA	9.3
Line 2008 Uprate - Loudoun to Cub Run	230	Jun-24	VA	3.0
Line 2008 Uprate - Cub Run to Walney	230	Jun-24	VA	2.5
Line #2242 Uprate - Dulles to Lincoln Park	230	Jun-24	VA	5.0
Nimbus 230kV Delivery - DEV	230	Jul-24	VA	12.0
Lucky Hill Substation	115/230	Jul-24	VA	7.5
Aviator 230kV Delivery - DEV	230	Sep-24	VA	42.0
Altair 230kV Delivery - NOVEC	230	Sep-24	VA	15.0
Trappe Rock 230kV Delivery - NOVEC	230	Sep-24	VA	8.0
Northstar 230 kV Delivery - NOVEC	230	Nov-24	VA	8.0
Thunderball (Wildwood) 230kV Delivery - NOVEC	230	Nov-24	VA	8.0
Line #53 (Chesterfield - Kevlar) Install Reymet Tap	115	Nov-24	VA	3.0
Line 53 and Line 72 EOL Partial Rebuild - Chesterfield to Brown Boveri Tap	115	Dec-24	VA	9.8
Line #1001 Battleboro to Chestnut EOL Rebuild	115	Dec-24	NC	14.0
Interconnection 230 kV Delivery - DEV	230	Dec-24	VA	16.0
Idylwood to Tyson's - New 230kV Line	230	Dec-24	VA	210.0
Lines #2063 and Partial #2164 Rebuild (Loudoun-OX CPCN)	230	Dec-24	VA	19.0
Lines #2181 and #2058 Hathaway - Rocky Mount (DEP) EOL Rebuild	230	Dec-24	VA	13.0
Line #254 Clubhouse-Lakeview EOL Rebuild	230	Dec-24	VA/NC	27.0
Line #1024 Chestnut - S Justice Branch EOL Rebuild	115	Dec-24	NC	5.1
Line #14 (Fudge Hollow to the demarcation point of AEP) EOL	138	Dec-24	VA	30.0
Stratus 230kV Delivery - DEV_Engineering	230	Dec-24	VA	24.0
Rixlew 230 kV Delivery - NOVEC	230	Dec-24	VA	10.0
Garysville 230kV Delivery - ODEC(PGEC)	230	Dec-24	VA	3.0
Convert 115kV Line #172 Liberty-Lomar and Line#197 Cannon Branch-Lomar to 230kV	230	Dec-24	VA	28.0

Appendix 3C - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Partial Line#5 Fork Union to Cunningham DP Retirement	115	Mar-25	VA	3.0
115kV Partial Line #83 Rebuild	115	Mar-25	VA	25.3
Park Center 230kV Delivery - DEV	230	May-25	VA	10.0
Relieve Line #219/#2066 Load Drop - Loop Trabue back to Midlothian Sub (Open Window Project)	230	May-25	VA	6.2
Charlottesville to Gordonsville 230kV Series Reactor	230	Jun-25	VA	11.4
Line #2210 Reconductor - Brambleton to Evergreen	230	Jun-25	VA	2.3
Line #2172 Reconductor - Brambleton to Evergreen	230	Jun-25	VA	2.3
Line #2213 Reconductor - Yardley to Cabin Run	230	Jun-25	VA	1.7
Line #514 (Goose Creek - Doubs(FE)) EOL	500	Jun-25	VA	7.6
Replace Overdutied 230kV Breaker L282 at Clifton Substation	230	Jun-25	VA	0.5
Line #2214 Uprate - Buttermilk to Roundtable	230	Jun-25	VA	4.8
Line #2186 Uprate-Shellhorn to Enterprise	230	Jun-25	VA	4.0
Line #2031 Uprate- Enterprise to Greenway to Roundtable	230	Jun-25	VA	5.9
Line #2223 Uprate- Roundtable to Lockridge	230	Jun-25	VA	2.6
Line #2188 Uprate-Shellhorn to Greenway to Lockridge	230	Jun-25	VA	3.8
Line #2218 Uprate - Sojourner to Runway DP to Shellhorn	230	Jun-25	VA	6.5
Line #2137 Uprate- Sojourner to Mars	230	Jun-25	VA	1.4
Line #502 Terminal Upgrade-Loudoun to Mosby	230	Jun-25	VA	6.3
Line #584 Terminal Upgrade-Loudoun to Mosby	230	Jun-25	VA	6.4
230kV Line Extension to Relieve Cloverhill Loop (Winters Branch -	230	Jun-25	VA	6.0
Line #2151 Uprate - Railroad DP to Gainesville	230	Jun-25	VA	6.1
Uprate Line 249 from Carson to Locks to Resolve Gen Deliv Violation	230	Jun-25	VA	22.0
Line #105 Tarboro-Parmele EOL Rebuild	115	Jul-25	NC	24.5
Butler Farm Sub - 230kV Delivery-DEV- Bailey DP-New Finneywood 500/230kV Sub	230/500	Jul-25	VA	220.0
Evans Creek Sub - Roanoke DP - 230kV Delivery - DEV	230	Aug-25	VA	30.0
Tunstall Sub - Hillcrest DP - 230kV Delivery - DEV -New Unity 500/230kV Sub	230	Aug-25	VA	140.0
Raines Sub - Interstate DP - 230kV Delivery - DEV	230	Aug-25	VA	20.0
Line #108 Boykins to Tunis EOL Rebuild	115	Dec-25	NC	46.0
Peninsula - TX 4 Replacement and 230kV Ring Bus	230	Dec-25	VA	27.2
Dawkins Branch 230kV Delivery - NOVEC (Iron Mountain)	230	Dec-25	VA	16.0
Takeoff 230kV Delivery Add Transformers - DEV	230	Dec-25	VA	20.0
Install 2nd 115kV 33.67 MVAR Cap bank at Harrisonburg	115	Dec-25	VA	1.3
Build new Walnut Creek 115 kV switching station	115/230	Dec-25	VA	24.3
Takeoff Substation 230kV interconnection for Poland Loop	230	Dec-25	VA	28.0
230kV Line #293 (Staunton-Valley) and 115kV Partial Line #83 Rebuild	115/230	Dec-25	VA	44.8
Hornbaker Sub-Avanti DP-NOVEC	230	Dec-25	VA	45.0
Line #81 and Partial Line #2056 Rebuild	115/230	Dec-25	NC	27.1
230kV to Relieve Waxpool Loop	230	Dec-25	VA	5.7
Line #2010 Underground Relocation	230	Dec-25	VA	40.0
230kV Line Extension to Relieve Poland Loop	230	Dec-25	VA	36.0
Line #569 (Loudoun to Morrisville) Partial Rebuild 1.3 miles	500	Dec-25	VA	4.2
Line #2209 Uprate Evergreen Mills to Yardley	230	Dec-25	VA	5.0
Line #2095 Uprate - Cabin Run to Shellhorn	230	Dec-25	VA	8.0
Line #2007 Lynnhaven to Thalia EOL Rebuild	230	Dec-25	VA	28.7
Line #2019 Greenwich to Thalia EOL Partial Rebuild	230	Dec-25	VA	14.3
Replace Brambleton Overdutied 230kV Breakers	230	Dec-25	VA	28.0
Line 265 Uprate - Sully to Takeoff	230	Dec-25	VA	2.0
Build New Duncan Store 115kV Switching Station	115	Dec-25	VA	11.0

Appendix 3C - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Line 2011 Uprate - Cannon Branch to Clifton	230	Dec-25	VA	31.7
Line #183 EOL	115/230	Dec-25	VA	30.0
Line #2114 Reconductor - Remington CT to Rollins Ford	230	Dec-25	VA	28.9
Partial Line #81 Carolina - S Justice Branch EOL Rebuild - Double Circuit Sections with Line #2056	115	Dec-25	NC	3.4
Line #77 Carolina-Roanoke Rapids Hydro EOL Rebuild	115	Dec-25	VA	7.4
Harrisonburg TX#6 EOL	69/230	Jan-26	VA	3.2
Mint Springs 230 kV Delivery - NOVEC	230	Jan-26	VA	16.0
Germanna 230kV Delivery - DEV	230	Apr-26	VA	55.0
Bring 2-230 kV Sources into White Oak SUB and Resolve 300 MW Load Loss Violation - Engineering Assessment	230	Apr-26	VA	28.0
Line 2104 Partial Uprate to Resolve Gen Deliv Violation	230	Jun-26	VA	20.2
Line 29 and 252 Possum Point to Aquia Harbor Rebuild	115/230	Jun-26	VA	38.0
Possum Point 2nd 500-230 kV TX (Ox Overloads) (PP 500kV - PP 230kV)	230/500	Jun-26	VA	23.1
Line 202 Uprate - Clark to Idylwood	230	Jun-26	VA	8.0
Line #29 Fredericksburg to Possum Pt Partial Rebuild	115	Jun-26	VA	19.2
Line #126 Partial Rebuild to Resolve Gen Deliverability Violation	115	Jun-26	NC	18.8
Convert Line 29 to 230 kV and Resolve 300 MW Load Loss Violation	115/230	Jun-26	VA	9.4
Line 211 228 Chesterfield to Hopewell Partial Rebuild	230	Jun-26	VA	7.4
Line #2226 Partial Rebuild - Clover to Easters (DNH)	230	Jun-26	VA	34.0
Install Cap Bank at Cloud 115kV Bus	115	Jun-26	VA	1.5
Line #574 Elmont-Ladysmith Rebuild	500	Jun-26	VA	93.0
Install Cap Bank at Lexington substation	500	Nov-26	VA	6.3
Bristers 500-230 kV TX Expansion	230/500	Dec-26	VA	65.0
Line #205 Locks to Tyler Rebuild (DNH)	230	Dec-26	VA	27.0
Line #9290 (Ox to Braddock) and Partial Line#2097 Uprate	230	Dec-26	VA	44.0
Line #2080 Uprate - Liberty to Railroad DP	230	Dec-26	VA	1.5
Line #2163 Uprate - Vint Hill to Liberty	230	Dec-26	VA	13.0
Line #2187 and #2228 Uprate - Pioneer DP to Liberty	230	Dec-26	VA	11.4
Line #272 (Dooms to Grottoes) EOL Rebuild	230	Dec-26	VA	30.8
Line #2056 Hornertown to Hathaway EOL Rebuild	230	Dec-26	NC	49.1
Occoquan 500-230 kV TX Expansion	230/500	Dec-26	VA	84.0
Remington CT 230 kV Terminal Upgrades (Line #2114)	230	Dec-26	VA	1.5
Idylwood - Convert Straight Bus to Breaker-and-a-Half	230	Dec-26	VA	159.0
Davis Drive - 230kV Ring Bus Expansion - Line Extension	230	Jun-27	VA	20.0
Ocean Court 230kV Delivery - DEV	230	Jun-27	VA	8.0
Spring Hill 230 kV Delivery - Dominion	230	Aug-27	VA	35.0
Potomac Yards Undergrounding & Glebe GIS Conversion	230	Sep-27	VA	202.0
Line #209 and Line #58 Skiffes to Yorktown EOL Partial Rebuild	230	Sep-27	VA	13.5
Partial Line #10 (Goshen to Craigsville) EOL Rebuild	115	Dec-27	VA	22.5
Nokesville to Hornbaker 230 kV Line	230	Dec-27	VA	139.0
Vint Hill 500-230 kV Expansion	230/500	Dec-27	VA	110.0
Line #557 (Chickahominy to Elmont) EOL Rebuild	500	Jun-28	VA	58.2
500-230kV Line Extension - Southern Option	230/500	Dec-28	VA	693.8
Barrister 230kV Delivery - DEV	230	Dec-28	VA	24.0

Appendix 4A: Total (DOM LSE) Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2011	30,779	28,957	7,960	10,555	273	1,921	80,445
2012	29,174	28,927	7,849	10,496	277	2,011	78,735
2013	30,184	29,372	8,097	10,261	276	1,984	80,174
2014	31,290	29,964	8,812	10,402	261	1,956	82,685
2015	30,923	30,282	8,765	10,159	275	1,981	82,385
2016	28,213	31,366	8,715	10,161	253	1,856	80,564
2017	29,737	32,292	8,638	10,555	258	1,609	83,088
2018	32,139	33,591	8,324	10,761	260	1,607	86,681
2019	31,439	35,296	7,302	10,645	263	1,580	86,524
2020	32,670	32,911	6,503	11,073	261	1,439	84,856
2021	31,598	35,203	6,716	10,740	245	1,570	86,071
2022	31,114	39,518	6,399	11,018	232	1,543	89,823
2023	31,436	43,633	6,758	10,406	246	1,608	94,086
2024	31,313	47,125	6,785	10,438	247	1,607	97,516
2025	30,998	48,387	6,770	10,392	246	1,595	98,388
2026	31,238	53,683	6,757	10,374	246	1,593	103,891
2027	31,502	56,355	6,729	10,355	246	1,589	106,777
2028	31,969	59,503	6,700	10,366	247	1,595	110,380
2029	32,369	62,569	6,635	10,322	246	1,584	113,725
2030	32,995	66,583	6,577	10,314	246	1,581	118,296
2031	33,686	70,934	6,510	10,312	246	1,579	123,267
2032	34,608	76,496	6,461	10,341	247	1,587	129,741
2033	35,211	81,895	6,377	10,311	246	1,578	135,618
2034	35,984	88,330	6,311	10,311	246	1,578	142,759
2035	36,776	95,352	6,245	10,310	246	1,580	150,510
2036	37,702	103,107	6,198	10,339	247	1,593	159,187
2037	38,207	110,753	6,116	10,309	246	1,589	167,220
2038	38,844	119,535	6,053	10,309	246	1,594	176,581

Note: Historic (2011 - 2022); Projected (2023 - 2038)
Appendix 4A has been provided with the 2023 Company Load Forecast instead of the 2023 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4B: Virginia Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2011	29,153	28,163	6,342	10,423	265	1,870	76,216
2012	27,672	28,063	6,235	10,370	269	1,958	74,568
2013	28,618	28,487	6,393	10,134	267	1,934	75,833
2014	29,645	29,130	6,954	10,272	253	1,906	78,160
2015	29,293	29,432	7,006	10,029	266	1,930	77,956
2016	26,652	30,537	6,947	10,033	245	1,803	76,217
2017	28,194	31,471	6,893	10,429	250	1,556	78,794
2018	30,437	32,752	6,598	10,633	252	1,555	82,228
2019	29,829	34,472	5,591	10,517	254	1,530	82,194
2020	30,969	32,159	4,872	10,924	253	1,393	80,570
2021	29,968	34,464	4,980	10,590	238	1,519	81,759
2022	29,474	38,750	4,888	10,868	225	1,496	85,701
2023	29,782	42,867	5,344	10,255	239	1,558	90,046
2024	29,672	46,372	5,315	10,285	240	1,558	93,442
2025	29,358	47,640	5,232	10,243	239	1,546	94,257
2026	29,598	52,942	5,318	10,219	239	1,544	99,860
2027	29,861	55,618	5,413	10,198	239	1,541	102,870
2028	30,324	58,763	5,060	10,209	240	1,546	106,142
2029	30,719	61,822	5,097	10,165	239	1,535	109,577
2030	31,338	65,827	4,914	10,156	239	1,532	114,007
2031	32,021	70,170	4,977	10,154	239	1,531	119,092
2032	32,936	75,723	4,944	10,184	240	1,538	125,565
2033	33,529	81,112	4,879	10,153	239	1,529	131,441
2034	34,290	87,534	4,779	10,152	239	1,530	138,525
2035	35,069	94,542	4,887	10,151	239	1,532	146,421
2036	35,983	102,282	4,501	10,181	240	1,544	154,730
2037	36,477	109,910	4,451	10,150	239	1,540	162,768
2038	37,103	118,673	4,555	10,149	239	1,546	172,265

Note: Historic (2011 - 2022); Projected (2023 - 2038)
Appendix 4B has been provided with the 2023 Company Load Forecast instead of the 2023 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4C: North Carolina Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2011	1,626	795	1,618	132	8	51	4,230
2012	1,502	864	1,614	126	8	53	4,167
2013	1,567	885	1,704	127	8	50	4,341
2014	1,645	834	1,858	130	8	50	4,525
2015	1,630	850	1,759	130	8	51	4,428
2016	1,562	829	1,768	128	8	53	4,347
2017	1,542	821	1,744	126	8	53	4,294
2018	1,701	839	1,725	128	8	52	4,453
2019	1,610	824	1,710	127	9	50	4,331
2020	1,701	751	1,630	149	8	46	4,286
2021	1,629	740	1,736	149	7	50	4,312
2022	1,640	768	1,511	150	7	47	4,122
2023	1,653	766	1,414	151	7	49	4,040
2024	1,640	754	1,470	152	7	49	4,074
2025	1,640	747	1,539	149	7	49	4,131
2026	1,639	741	1,439	155	7	49	4,031
2027	1,641	738	1,316	157	7	49	3,907
2028	1,645	740	1,640	157	7	49	4,238
2029	1,650	747	1,537	157	7	49	4,148
2030	1,657	755	1,664	158	7	48	4,289
2031	1,664	764	1,533	158	7	48	4,175
2032	1,673	773	1,516	158	7	49	4,176
2033	1,682	783	1,498	158	7	48	4,176
2034	1,693	795	1,531	158	7	48	4,234
2035	1,707	810	1,358	158	7	48	4,089
2036	1,720	825	1,696	159	7	49	4,456
2037	1,731	842	1,665	159	7	49	4,453
2038	1,741	861	1,499	159	7	49	4,317

Note: Historic (2011 - 2022); Projected (2023 - 2038)
Appendix 4C has been provided with the 2023 Company Load Forecast instead of the 2023 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4D: Total (DOM LSE) Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2011	2,171,795	233,760	535	29,104	3,031	5	2,438,229
2012	2,187,670	234,947	514	29,114	3,246	4	2,455,496
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	2,323,662	243,701	644	28,716	4,398	3	2,601,124
2019	2,362,949	246,043	634	28,452	4,792	3	2,642,873
2020	2,397,544	246,865	626	29,883	4,889	3	2,679,810
2021	2,427,368	249,622	615	29,845	5,109	3	2,712,562
2022	2,451,831	251,673	610	29,709	5,196	3	2,739,022
2023	2,468,022	252,745	608	29,687	5,286	3	2,756,350
2024	2,499,287	255,100	602	29,757	5,430	3	2,790,179
2025	2,531,721	257,525	596	29,828	5,574	3	2,825,247
2026	2,564,595	259,976	590	29,893	5,718	3	2,860,774
2027	2,597,827	262,447	584	29,954	5,862	3	2,896,675
2028	2,631,236	264,928	578	30,009	6,006	3	2,932,761
2029	2,664,561	267,406	572	30,060	6,150	3	2,968,751
2030	2,697,472	269,860	566	30,106	6,294	3	3,004,300
2031	2,729,661	272,273	560	30,145	6,438	3	3,039,079
2032	2,760,879	274,630	554	30,177	6,582	3	3,072,825
2033	2,790,937	276,922	548	30,202	6,726	3	3,105,337
2034	2,819,694	279,139	542	30,221	6,870	3	3,136,468
2035	2,847,084	281,277	536	30,233	7,014	3	3,166,147
2036	2,873,169	283,340	530	30,240	7,158	3	3,194,439
2037	2,898,044	285,334	524	30,241	7,302	3	3,221,447
2038	2,921,784	287,262	518	30,238	7,446	3	3,247,250

Note: Historic (2011 - 2022); Projected (2023 - 2038)
Appendix 4D has been provided with the 2023 Company Load Forecast instead of the 2023 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4E: Virginia Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2011	2,070,786	218,341	482	27,252	2,639	3	2,319,503
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	2,220,797	227,757	594	26,872	4,017	2	2,480,039
2019	2,259,491	229,988	584	26,614	4,417	2	2,521,096
2020	2,292,457	230,782	576	27,901	4,516	2	2,556,234
2021	2,321,357	233,334	567	27,836	4,741	2	2,587,837
2022	2,344,903	235,269	563	27,704	4,824	2	2,613,265
2023	2,360,423	236,236	561	27,705	4,920	2	2,629,846
2024	2,390,543	238,431	555	27,767	5,066	2	2,662,364
2025	2,421,791	240,692	549	27,830	5,212	2	2,696,076
2026	2,453,461	242,976	543	27,888	5,359	2	2,730,228
2027	2,485,477	245,280	537	27,941	5,505	2	2,764,742
2028	2,517,663	247,594	531	27,991	5,652	2	2,799,432
2029	2,549,768	249,903	525	28,036	5,798	2	2,834,031
2030	2,581,475	252,191	519	28,076	5,945	2	2,868,207
2031	2,612,486	254,440	513	28,110	6,091	2	2,901,642
2032	2,642,561	256,638	507	28,139	6,237	2	2,934,084
2033	2,671,518	258,774	501	28,162	6,384	2	2,965,341
2034	2,699,223	260,841	495	28,178	6,530	2	2,995,269
2035	2,725,611	262,834	489	28,189	6,677	2	3,023,802
2036	2,750,741	264,758	483	28,195	6,823	2	3,051,001
2037	2,774,706	266,616	477	28,196	6,970	2	3,076,966
2038	2,797,577	268,414	471	28,193	7,116	2	3,101,772

Note: Historic (2011 - 2022); Projected (2023 - 2038)
Appendix 4E has been provided with the 2023 Company Load Forecast instead of the 2023 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4F: North Carolina Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2011	101,009	15,418	53	1,852	392	2	118,726
2012	101,024	15,501	50	1,849	390	2	118,816
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	102,865	15,944	50	1,844	381	1	121,085
2019	103,458	16,055	50	1,838	375	1	121,777
2020	105,087	16,083	50	1,982	373	1	123,576
2021	106,011	16,288	48	2,009	368	1	124,725
2022	106,928	16,404	47	2,005	372	1	125,757
2023	107,599	16,509	47	1,982	366	1	126,505
2024	108,743	16,669	47	1,990	364	1	127,814
2025	109,930	16,833	47	1,998	362	1	129,171
2026	111,134	16,999	47	2,005	359	1	130,545
2027	112,350	17,167	47	2,012	357	1	131,934
2028	113,573	17,335	47	2,019	354	1	133,329
2029	114,793	17,503	47	2,024	352	1	134,720
2030	115,997	17,669	47	2,030	349	1	136,093
2031	117,175	17,832	47	2,034	347	1	137,437
2032	118,318	17,992	47	2,038	345	1	138,741
2033	119,418	18,147	47	2,041	342	1	139,997
2034	120,471	18,298	47	2,043	340	1	141,199
2035	121,473	18,443	47	2,044	337	1	142,345
2036	122,428	18,582	47	2,045	335	1	143,438
2037	123,339	18,717	47	2,045	332	1	144,481
2038	124,207	18,848	47	2,045	330	1	145,478

Note: Historic (2011 - 2022); Projected (2023 - 2038)
Appendix 4F has been provided with the 2023 Company Load Forecast instead of the 2023 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4G: LSE Summer and Winter Peak Demand (MW)

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)
2011	17,521	15,143
2012	16,787	14,544
2013	16,366	15,106
2014	16,249	16,840
2015	16,502	18,434
2016	16,914	16,173
2017	16,350	16,618
2018	16,528	17,792
2019	16,599	16,842
2020	16,356	14,661
2021	16,462	14,469
2022	17,131	17,813
2023	17,730	17,157
2024	18,010	17,497
2025	18,157	17,554
2026	18,828	18,022
2027	19,173	18,199
2028	19,597	18,467
2029	20,021	19,106
2030	20,650	19,558
2031	21,346	20,001
2032	22,153	20,463
2033	23,019	20,933
2034	23,963	21,747
2035	24,972	22,627
2036	26,111	23,458
2037	27,220	24,162
2038	28,483	24,971

Note: Historic (2011 - 2022); Projected (2023 - 2038)
Appendix 4G has been provided with the 2022 Company Load Forecast instead of the 2022 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4H - Projected Summer & Winter Peak Load & Energy Forecast

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

I. PEAK LOAD AND ENERGY FORECAST

		(ACTUAL)[1]										(PROJECTED)								
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
1. Utility Peak Load (MW)																			
A. Summer																			
1. Base Forecast (LSE Equivalent)	16,356	16,462	17,131	17,863	18,329	18,619	19,341	19,710	20,105	20,535	21,025	21,539	22,178	22,865	23,688	24,562	25,505	26,507	27,683
2. Energy Efficiency & Demand Response[2][3]	(74)	(331)	(186)	(198)	(396)	(604)	(655)	(701)	(722)	(734)	(735)	(742)	(758)	(783)	(785)	(790)	(778)	(790)	(822)
3. Customer Choice (non data center)[5]	-	-	-	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)
4. Adjusted Load	16,282	16,131	16,945	16,998	17,266	17,348	18,019	18,341	18,715	19,133	19,622	20,129	20,752	21,415	22,235	23,104	24,059	25,050	26,193
5. % Increase in Adjusted Load (from previous year)	(0.01)	(0.01)	0.05	0.00	0.02	0.00	0.04	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.05
B. Winter																			
1. Base Forecast (LSE Equivalent)	14,661	14,469	17,813	15,914	16,329	16,588	17,231	17,560	17,911	18,295	18,731	19,189	19,758	20,371	21,104	21,882	22,722	23,615	24,662
2. Energy Efficiency & Demand Response[2][3]	(14)	(331)	(228)	(198)	(396)	(604)	(655)	(701)	(722)	(734)	(735)	(742)	(758)	(783)	(785)	(790)	(778)	(790)	(822)
3. Customer Choice (non data center)[5]	-	-	-	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)	(668)
4. Adjusted Load	14,647	14,138	17,585	15,049	15,266	15,316	15,909	16,191	16,521	16,893	17,328	17,779	18,333	18,920	19,651	20,425	21,276	22,158	23,173
5. % Increase in Adjusted Load (from previous year)	(0.12)	(0.03)	0.24	(0.14)	0.01	0.00	0.04	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.05
2. Energy (GWh)																			
A. Base Forecast (LSE Equivalent)	81,440	86,386	91,180	100,304	105,180	107,484	113,569	116,922	120,872	124,267	128,710	133,323	139,397	144,817	151,513	158,875	167,199	174,910	184,358
B. Additional Forecast Future BTM[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Energy Efficiency & Demand Response[2][3]	(401)	(1,657)	(1,136)	(990)	(1,964)	(2,960)	(3,057)	(3,152)	(3,234)	(3,259)	(3,276)	(3,312)	(3,355)	(3,379)	(3,405)	(3,405)	(3,435)	(3,498)	(3,612)
D. Customer Choice (non data center)[5]	-	-	-	(4,319)	(4,330)	(4,319)	(4,319)	(4,319)	(4,330)	(4,319)	(4,319)	(4,319)	(4,330)	(4,319)	(4,319)	(4,319)	(4,330)	(4,319)	(4,319)
E. Adjusted Energy	81,039	84,729	90,044	94,996	98,886	100,205	106,193	109,451	113,308	116,689	121,115	125,692	131,712	137,118	143,789	151,151	159,434	167,093	176,427
F. % Increase in Adjusted Energy	(0.06)	0.05	0.06	0.05	0.04	0.01	0.06	0.03	0.04	0.03	0.04	0.04	0.05	0.04	0.05	0.05	0.05	0.05	0.06

(1) Actual metered data.

(2) Demand response programs are not classified as capacity resources and are included in adjusted load.

(3) 2020 and 2021 actual historical data based upon measured and verified EM&V results . 2022 projected values represent modeled DSM firm capacity.

(4) Future behind-the-meter, which is not included in the base forecast.

Appendix 4I - Required Reserve Margin (for Plan B)

Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)				(PROJECTED)														
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
I. Reserve Margin(1)																			
1. Summer Reserve Margin																			
a. MW(1)	2,827	3,006	2,348	2,533	2,538	2,550	2,649	2,696	2,751	2,813	2,884	2,959	3,051	3,148	3,269	3,396	3,537	3,682	3,850
b. Percent of Load	17.3%	18.3%	13.7%	14.9%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%
c. Actual Reserve Margin(2)	N/A	N/A	N/A	3.6%	4.9%	5.1%	2.7%	7.3%	10.7%	8.7%	7.3%	5.3%	3.3%	4.5%	3.4%	3.2%	3.8%	3.2%	2.9%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	4,482	4,538	4,582	4,759	4,847	5,134	5,053	5,178	5,309	5,470	5,643	5,853	6,076	6,319	6,574	6,871
b. Percent of Load	N/A	N/A	N/A	29.8%	29.7%	29.9%	29.9%	29.9%	31.1%	29.9%	29.9%	29.9%	29.8%	29.8%	29.8%	29.7%	29.7%	29.7%	29.7%
c. Actual Reserve Margin(2)	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
II. Annual Loss-of-Load Hours(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

(1) To be calculated based on total net capability for summer and winter.
(2) Does not include spot purchases of capacity or energy efficiency programs.
(3) The Company follows PJM reserve requirements which are based on loss of load expectation.

Appendix 4J – Summer and Winter Peak

Company Name: Virginia Electric and Power Company

Schedule 5

POWER SUPPLY DATA

	(ACTUAL)				(PROJECTED)														
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak[1]	16,282	16,131	16,945	16,998	17,266	17,348	18,019	18,341	18,715	19,133	19,622	20,129	20,752	21,415	22,235	23,104	24,059	25,050	26,193
b. Other Commitments[2]	74	331	186	865	1,063	1,272	1,322	1,369	1,390	1,402	1,403	1,410	1,425	1,450	1,453	1,458	1,446	1,457	1,490
c. Total System Summer Peak	16,356	16,462	17,131	17,863	18,329	18,619	19,341	19,710	20,105	20,535	21,025	21,539	22,178	22,865	23,688	24,562	25,505	26,507	27,683
d. Percent Increase in Total Summer Peak	-1.5%	0.6%	4.1%	4.3%	2.6%	1.6%	3.9%	1.9%	2.0%	2.1%	2.4%	2.4%	3.0%	3.1%	3.6%	3.7%	3.8%	3.9%	4.4%
2. Winter																			
a. Adjusted Winter Peak[1]	14,647	14,138	17,585	15,049	15,266	15,316	15,909	16,191	16,521	16,893	17,328	17,779	18,333	18,920	19,651	20,425	21,276	22,158	23,173
b. Other Commitments[2]	14	331	228	865	1,063	1,272	1,322	1,369	1,390	1,402	1,403	1,410	1,425	1,450	1,453	1,458	1,446	1,457	1,490
c. Total System Winter Peak	14,661	14,469	17,813	15,914	16,329	16,588	17,231	17,560	17,911	18,295	18,731	19,189	19,758	20,371	21,104	21,882	22,722	23,615	24,662
d. Percent Increase in Total Winter Peak	-12.9%	-1.3%	23.1%	-10.7%	2.6%	1.6%	3.9%	1.9%	2.0%	2.1%	2.4%	2.4%	3.0%	3.1%	3.6%	3.7%	3.8%	3.9%	4.4%

(1) Adjusted load from Appendix 4H.

(2) Includes firm additional forecast, conservation efficiency, peak adjustments, and customer choice from Appendix 4H.

Appendix 4K – Wholesale Power Sales Contracts

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

WHOLESALE POWER SALES CONTRACTS

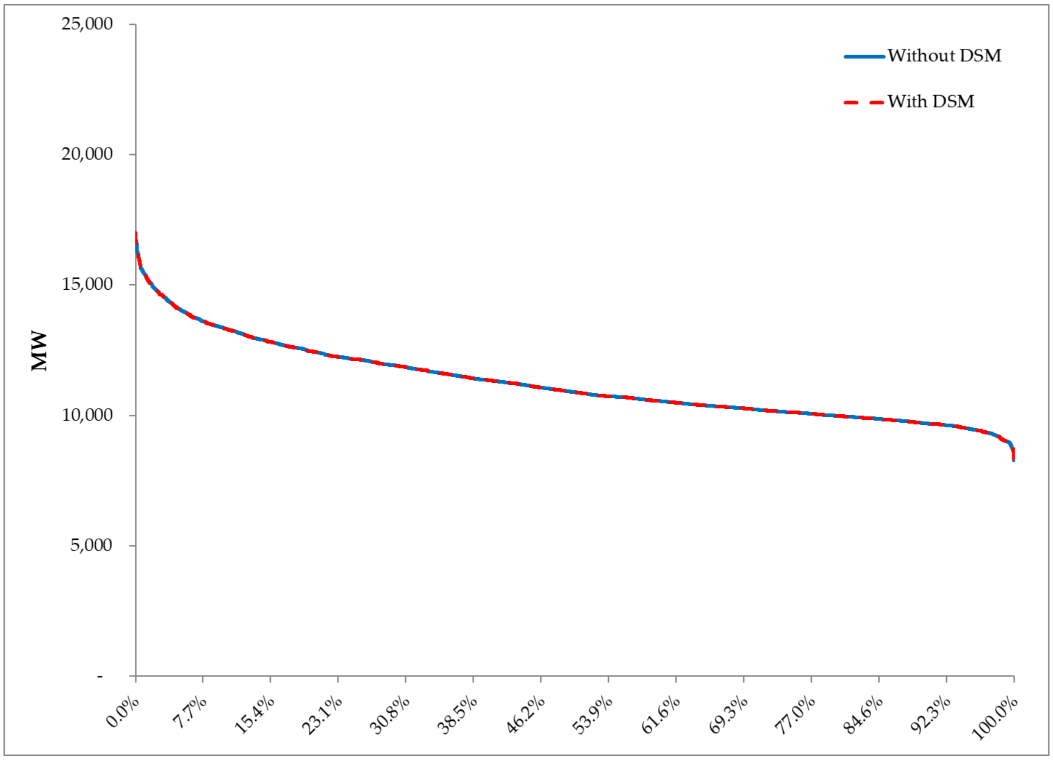
			(Actual)[2]		
Entity	**Contract Length**	**Contract Type**	**2020**	**2021**	**2022**
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements[1]	9	10	13
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements[1]	10	10	11
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements[1]	283	291	286

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

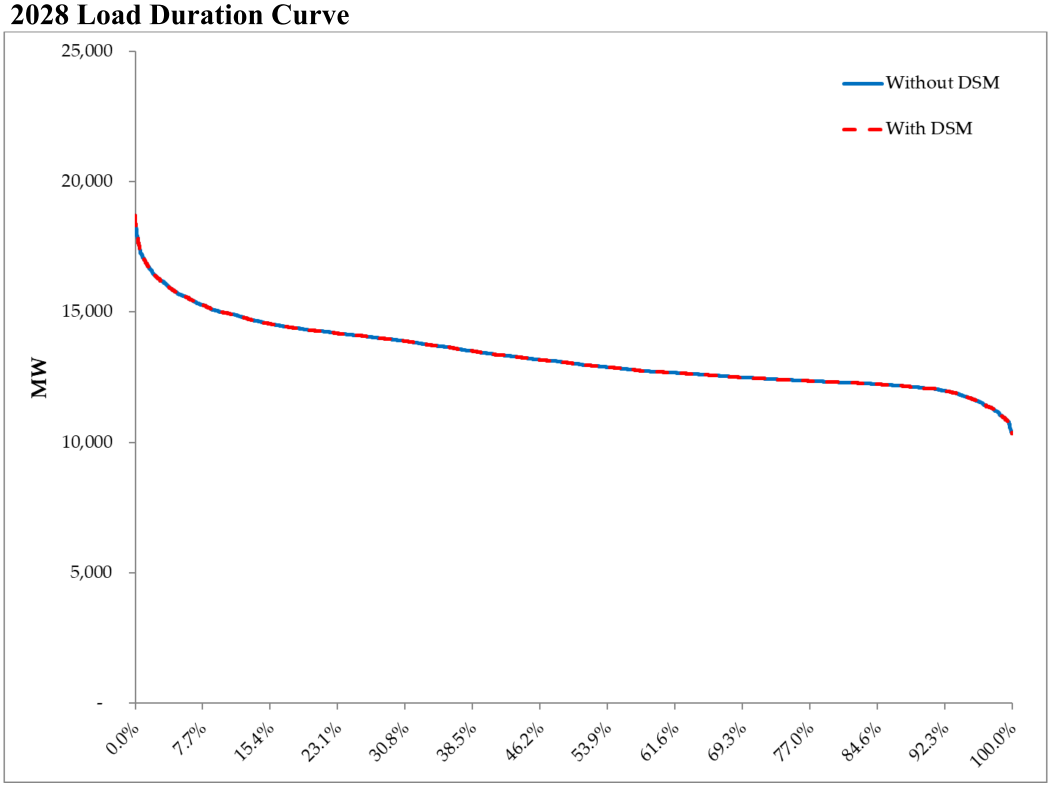
(2) Actual customer peak load measures are included.

Appendix 4L – Load Duration Curves

2023 Load Duration Curve

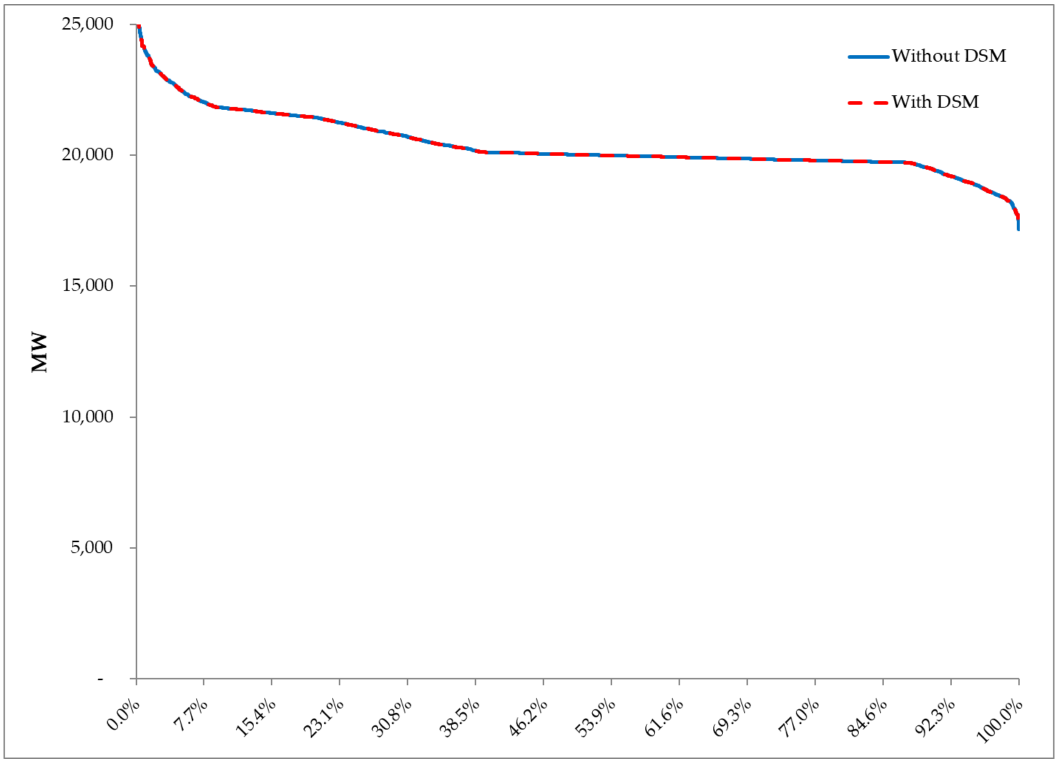


2028 Load Duration Curve



Appendix 4L – Load Duration Curves

2038 Load Duration Curve



Appendix 4M – Economic Assumptions used in the Sales and Hourly Budget Forecast Model
(Annual Growth Rate)

	Economic Assumptions Used In the Sales and Hourly Budget Forecst Model (Annual Growth Rate)																
Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**CAGR**
Population: Total, (Ths.)	8,702	8,745	8,780	8,812	8,844	8,874	8,904	8,934	8,964	8,993	9,020	9,047	9,072	9,097	9,121	9,144	0.3%
Disposable Personal Income: (Mil. 12$; SAAR)	486,652	500,642	513,465	527,700	540,982	553,761	566,552	578,825	590,711	602,661	614,879	627,070	639,215	651,383	663,610	675,672	2.2%
Per Capia Disposable Personal Income: (C 12$; SAAR)	47,978	49,276	50,315	51,464	52,554	53,612	54,677	55,684	56,653	57,627	58,630	59,637	60,643	61,655	62,671	63,677	1.9%
Residential Permits: Total, (#, SAAR)	46,384	49,593	50,348	51,118	51,603	51,656	51,065	49,858	48,128	46,010	43,601	40,963	38,396	36,051	33,832	31,759	-2.5%
Employment: Total Manufacturing, (Ths., SA)	238	240	240	239	238	236	234	232	230	228	226	224	222	221	219	217	-0.6%
Employment: Total Government, (Ths., SA)	722	727	730	734	739	745	750	754	757	759	762	765	767	769	771	774	0.5%
Employment: Military personnel, (Ths., SA)	118	117	117	116	116	116	115	115	114	114	114	113	113	112	112	112	-0.4%
Employment: State and local government, (Ths., SA)	534	539	543	547	552	557	563	566	569	571	574	576	578	580	582	584	0.6%
Employment: Commercial Sector, (Ths., SA)	2,935	2,967	2,997	3,015	3,033	3,053	3,073	3,091	3,108	3,123	3,139	3,155	3,170	3,184	3,197	3,210	0.6%
Gross State Product: Total Manufacturing, (Bil. Ch. 2012 USD, SAAR)	40.7	41.4	42.5	43.5	44.4	45.3	46.0	46.6	47.2	47.8	48.5	49.2	49.9	50.6	51.2	51.9	1.6%
Gross State Product: Total, (Bil. Ch. 2012 USD, SAAR)	513	525	540	556	571	585	599	611	622	634	646	658	670	682	694	706	2.2%
Gross State Product: State and Local Government,(Bil. Chained 2012 $, SA	38.7	39.1	39.9	40.6	41.3	41.9	42.5	43.1	43.6	44.1	44.7	45.1	45.6	45.9	46.2	46.5	1.2%

Source: Moody's Analytics (formerly Economy.com)

Appendix 4N: Base Case Price Forecast (Nominal $)

	Fuel Price					Power and REC Prices			RTO Capacity Prices		Emission Prices				
Year	Henry Hub Natural Gas ($/MMBtu)	Zone 5 Delivered Natural Gas ($/MMBtu)	CAPP CSX: 12,500 1%S FOB ($/ton)	No. 2 Oil ($/MMBtu)	1% No.6 Oil ($/MMBtu)	PJM-DOM On-Peak ($/MWh)	PJM-DOM Off-Peak ($/MWh)	PJM Tier 1 REC Prices ($/MWh)	($/kW-yr)	($/MW-day)*	SO_2 ($/Ton)	CSAPR Ozone NO_x ($/Ton)	CSAPR Annual NO_x ($/Ton)	Federal CO_2 Price ($/Ton)	RGGI CO_2 ($/Ton)
2023	2.70	3.44	96.00	19.44	11.25	51.90	39.35	28.70	14.20	38.89	2.45	16,345.47	2.04	-	13.27
2024	3.41	4.96	100.35	18.52	11.05	54.98	44.28	27.42	16.00	43.85	2.53	16,588.87	2.13	-	-
2025	4.13	4.71	105.32	17.90	11.71	57.08	44.82	25.54	22.30	61.10	2.93	9,997.19	2.74	-	-
2026	4.15	3.65	95.69	17.96	12.15	52.96	42.65	26.00	28.68	78.57	3.29	3,955.39	3.28	-	-
2027	4.05	3.44	86.41	18.30	12.37	47.50	39.85	23.92	35.31	96.73	3.36	3,024.10	3.36	-	-
2028	3.96	3.36	78.03	18.66	12.61	43.01	37.38	20.38	42.20	115.61	3.43	2,055.99	3.43	-	-
2029	3.86	3.21	70.64	19.03	12.86	38.45	34.33	17.58	49.37	135.25	3.50	1,048.75	3.50	-	-
2030	3.76	3.27	65.03	19.39	13.10	36.01	33.32	14.02	56.76	155.51	3.56	3.56	3.56	-	-
2031	3.96	3.43	65.84	19.75	13.35	37.18	34.72	13.27	62.45	171.09	3.63	3.63	3.63	-	-
2032	4.17	3.61	67.49	20.11	13.59	38.50	36.20	12.52	66.88	183.23	3.70	3.70	3.70	-	-
2033	4.38	3.83	69.35	20.48	13.84	40.23	38.07	11.76	71.45	195.76	3.77	3.77	3.77	-	-
2034	4.60	4.06	71.19	20.87	14.10	41.91	39.98	11.00	76.20	208.77	3.84	3.84	3.84	-	-
2035	4.82	4.31	73.07	21.27	14.37	43.92	42.06	10.25	81.15	222.32	3.92	3.92	3.92	-	-
2036	4.83	4.33	74.77	21.68	14.65	45.46	44.79	9.25	86.22	236.23	3.99	3.99	3.99	3.18	-
2037	4.84	4.31	76.49	22.11	14.94	46.65	47.28	8.19	91.44	250.53	4.07	4.07	4.07	6.49	-
2038	4.85	4.32	78.37	22.56	15.24	48.02	49.94	7.01	96.86	265.37	4.16	4.16	4.16	9.93	-

Note:

1) The 2023 - 2025 prices are a blend of futures/forwards and forecast prices for all commodities except capacity. 2026 and beyond are forecast prices.

2) Capacity prices reflect PJM RPM auction clearing prices through delivery year 2023/2024, forecast thereafter.

3) CO2 prices reflect RGGI Market Price for 2023 and the federal carbon price forecast 2036 and beyond.

4) CSAPR SO_2 and nationwide SO_2 prices are used as the SO_2 market price.

*RTO Capacity prices are restated in the units used by the PJM Capacity market.

Appendix 4N: Commodity Price Forecast, Natural Gas

	Henry Hub Natural Gas ($/MMBtu)			
Year	Base Case Commodity Forecast	VA in RGGI Commodity Forecast	High Fuel Price Commodity Forecast	Low Fuel Price Case Commodity Forecast
2023	2.70	2.70	2.70	2.70
2024	3.41	3.41	3.44	3.37
2025	4.13	4.13	4.38	3.37
2026	4.15	4.15	4.95	3.06
2027	4.05	4.05	5.26	3.15
2028	3.96	3.96	5.58	3.27
2029	3.86	3.86	5.92	3.40
2030	3.76	3.76	6.26	3.53
2031	3.96	3.96	6.56	3.62
2032	4.17	4.17	6.86	3.70
2033	4.38	4.38	7.17	3.79
2034	4.60	4.60	7.50	3.88
2035	4.82	4.82	7.84	3.98
2036	4.83	4.83	8.15	4.03
2037	4.84	4.84	8.46	4.08
2038	4.85	4.85	8.79	4.14

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, Natural Gas

	Zone 5 Delivered Natural Gas ($/MMBtu)			
Year	Base Case Commodity Forecast	VA in RGGI Commodity Forecast	High Fuel Price Commodity Forecast	Low Fuel Price Case Commodity Forecast
2023	3.44	3.44	3.44	3.44
2024	4.96	4.96	5.00	4.93
2025	4.71	4.71	4.96	3.95
2026	3.65	3.65	4.46	2.56
2027	3.44	3.44	4.66	2.55
2028	3.36	3.36	4.99	2.67
2029	3.21	3.21	5.26	2.74
2030	3.27	3.27	5.77	3.04
2031	3.43	3.43	6.03	3.09
2032	3.61	3.61	6.31	3.15
2033	3.83	3.83	6.62	3.24
2034	4.06	4.06	6.96	3.35
2035	4.31	4.31	7.32	3.47
2036	4.33	4.33	7.64	3.53
2037	4.31	4.31	7.93	3.55
2038	4.32	4.33	8.27	3.61

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, Coal (FOB)

	CAPP CSX: 12,500 1%S FOB ($/ton)			
Year	**Base Case Commodity Forecast**	**VA in RGGI Commodity Forecast**	**High Fuel Price Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2023	96.00	96.00	96.00	96.00
2024	100.35	100.35	100.35	100.35
2025	105.32	105.32	105.33	105.32
2026	95.69	95.69	95.76	95.69
2027	86.41	86.41	86.55	86.41
2028	78.03	78.03	78.35	78.03
2029	70.64	70.64	70.93	70.64
2030	65.03	65.03	65.45	65.03
2031	65.84	65.84	66.25	65.84
2032	67.49	67.49	67.97	67.49
2033	69.35	69.35	69.75	69.35
2034	71.19	71.19	71.66	71.19
2035	73.07	73.07	73.44	73.07
2036	74.77	74.77	75.12	74.77
2037	76.49	76.49	76.94	76.49
2038	78.37	78.37	78.69	78.37

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, Oil

	No. 2 Oil ($/MMBtu)			
Year	**Base Case Commodity Forecast**	**VA in RGGI Commodity Forecast**	**High Fuel Price Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2023	19.44	19.44	19.44	19.44
2024	18.52	18.52	18.56	18.48
2025	17.90	17.90	18.61	17.32
2026	17.96	17.96	19.37	16.73
2027	18.30	18.30	19.89	16.70
2028	18.66	18.66	20.31	16.73
2029	19.03	19.03	21.82	17.11
2030	19.39	19.39	22.39	17.20
2031	19.75	19.75	22.89	17.34
2032	20.11	20.11	23.49	17.93
2033	20.48	20.48	24.05	18.33
2034	20.87	20.87	24.61	18.63
2035	21.27	21.27	24.99	18.93
2036	21.68	21.68	25.47	19.21
2037	22.11	22.11	25.88	19.61
2038	22.56	22.56	26.27	20.00

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, Oil

	1% No. 6 Oil ($/MMBtu)			
Year	Base Case Commodity Forecast	VA in RGGI Commodity Forecast	High Fuel Price Commodity Forecast	Low Fuel Price Case Commodity Forecast
2023	11.25	11.25	11.25	11.25
2024	11.05	11.05	11.08	11.03
2025	11.71	11.71	12.25	11.26
2026	12.15	12.15	13.23	11.20
2027	12.37	12.37	13.59	11.14
2028	12.61	12.61	13.87	11.13
2029	12.86	12.86	15.00	11.39
2030	13.10	13.10	15.41	11.42
2031	13.35	13.35	15.75	11.50
2032	13.59	13.59	16.18	11.91
2033	13.84	13.84	16.57	12.19
2034	14.10	14.10	16.97	12.38
2035	14.37	14.37	17.22	12.58
2036	14.65	14.65	17.55	12.75
2037	14.94	14.94	17.83	13.02
2038	15.24	15.24	18.08	13.28

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, On-Peak Power Price

	PJM-DOM On-Peak ($/MWh)			
Year	**Base Case Commodity Forecast**	**VA in RGGI Commodity Forecast**	**High Fuel Price Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2023	51.90	51.90	51.90	51.90
2024	54.98	55.01	55.44	54.65
2025	57.08	57.88	60.13	48.05
2026	52.96	54.00	61.30	41.49
2027	47.50	48.27	59.05	39.58
2028	43.01	43.57	57.39	37.71
2029	38.45	38.81	55.10	35.14
2030	36.01	36.19	53.83	34.63
2031	37.18	37.38	55.82	34.98
2032	38.50	38.73	57.97	35.47
2033	40.23	40.50	60.56	36.38
2034	41.91	42.22	63.13	37.27
2035	43.92	44.26	66.08	38.48
2036	45.46	45.74	69.35	40.40
2037	46.65	46.86	72.41	42.01
2038	48.02	48.17	75.59	43.87

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, Off-Peak Power Price

	PJM-DOM Off-Peak ($/MWh)			
Year	Base Case Commodity Forecast	VA in RGGI Commodity Forecast	High Fuel Price Commodity Forecast	Low Fuel Price Case Commodity Forecast
2023	39.35	39.35	39.35	39.35
2024	44.28	44.29	44.66	44.01
2025	44.82	45.18	47.46	37.40
2026	42.65	43.12	49.68	32.65
2027	39.85	40.22	49.71	32.42
2028	37.38	37.66	49.91	32.11
2029	34.33	34.50	49.21	30.96
2030	33.32	33.42	49.94	31.92
2031	34.72	34.84	52.09	32.58
2032	36.20	36.35	54.32	33.31
2033	38.07	38.29	56.99	34.45
2034	39.98	40.23	59.71	35.60
2035	42.06	42.36	62.61	36.93
2036	44.79	45.03	66.93	40.05
2037	47.28	47.46	71.28	42.99
2038	49.94	50.07	75.81	46.19

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, PJM Tier 1 Renewable Energy Certificates

	PJM Tier 1 REC Prices ($/MWh)			
Year	**Base Case Commodity Forecast**	**VA in RGGI Commodity Forecast**	**High Fuel Price Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2023	28.70	28.70	28.70	28.70
2024	27.42	27.42	27.42	27.42
2025	25.54	25.54	25.54	25.54
2026	26.00	25.82	12.06	30.59
2027	23.92	23.82	8.81	28.16
2028	20.38	20.32	4.61	24.44
2029	17.58	17.57	3.53	21.74
2030	14.02	14.02	3.60	18.55
2031	13.27	13.27	3.67	18.34
2032	12.52	12.52	3.74	18.14
2033	11.76	11.76	3.81	17.94
2034	11.00	11.00	3.88	17.77
2035	10.25	10.25	3.95	17.62
2036	9.25	9.26	4.03	16.84
2037	8.19	8.19	4.11	16.02
2038	7.01	7.01	4.20	15.18

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, VA REC

	VA REC Prices ($/MWh)			
Year	**Base Case Commodity Forecast**	**VA in RGGI Commodity Forecast**	**High Fuel Price Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2023	24.52	24.52	24.52	24.52
2024	24.54	24.54	24.54	24.54
2025	47.45	47.45	47.45	47.45
2026	26.03	25.85	11.90	30.69
2027	23.92	23.82	8.81	28.16
2028	20.38	20.32	4.61	24.44
2029	17.58	17.57	3.53	21.74
2030	14.02	14.02	3.60	18.55
2031	13.27	13.27	3.67	18.34
2032	12.52	12.52	3.74	18.14
2033	11.76	11.76	3.81	17.94
2034	11.00	11.00	3.88	17.77
2035	10.25	10.25	3.95	17.62
2036	9.25	9.26	4.03	16.91
2037	8.19	8.19	4.11	16.14
2038	7.01	7.01	4.20	15.35

Note: Reflects the ICF forecast price for the entire period rather than blending the ICF forecast with market prices.

Appendix 4N: Commodity Price Forecast, PJM RTO Capacity

	PJM RTO Capacity Prices ($/kW-yr)			
Year	Base Case Commodity Forecast	VA in RGGI Commodity Forecast	High Fuel Price Commodity Forecast	Low Fuel Price Case Commodity Forecast
2023	14.20	14.20	14.20	14.20
2024	16.00	16.00	15.37	15.99
2025	22.30	22.30	20.55	22.27
2026	28.68	28.67	25.77	28.62
2027	35.31	35.30	31.19	35.22
2028	42.20	42.19	36.83	42.08
2029	49.37	49.35	42.70	49.22
2030	56.76	56.75	48.74	56.59
2031	62.45	62.41	54.09	62.67
2032	66.88	66.79	58.94	67.82
2033	71.45	71.31	63.95	73.15
2034	76.20	76.01	69.15	78.67
2035	81.15	80.90	74.56	84.42
2036	86.22	86.00	79.86	89.18
2037	91.44	91.28	85.11	93.23
2038	96.86	96.76	90.57	97.43

Note: PJM RPM auction clearing price through delivery year 2023/24, forecast thereafter.

Appendix 4N: Commodity Price Forecast, PJM RTO Capacity

	RTO Capacity Prices ($/MW-day)			
Year	Base Case Commodity Forecast	VA in RGGI Commodity Forecast	High Fuel Price Commodity Forecast	Low Fuel Price Case Commodity Forecast
2023	38.89	38.89	38.89	38.89
2024	43.85	43.84	42.11	43.81
2025	61.10	61.10	56.31	61.00
2026	78.57	78.55	70.60	78.40
2027	96.73	96.71	85.45	96.49
2028	115.61	115.58	100.90	115.29
2029	135.25	135.22	116.97	134.86
2030	155.51	155.47	133.55	155.04
2031	171.09	170.98	148.19	171.71
2032	183.23	182.98	161.47	185.82
2033	195.76	195.38	175.19	200.40
2034	208.77	208.25	189.44	215.54
2035	222.32	221.66	204.27	231.30
2036	236.23	235.60	218.79	244.34
2037	250.53	250.08	233.19	255.43
2038	265.37	265.10	248.14	266.92

Note:

1) RTO capacity prices are restated in the units used by the PJM capacity market.

2) PJM RPM auction clearing price through delivery year 2023/24, forecast thereafter.

Appendix 4N: Commodity Price Forecast, SO_2 Emission Allowances

	SO_2 (\$/Ton)			
Year	Base Case Commodity Forecast	VA in RGGI Commodity Forecast	High Fuel Price Commodity Forecast	Low Fuel Price Case Commodity Forecast
2023	2.45	2.45	2.45	2.45
2024	2.53	2.53	2.53	2.53
2025	2.93	2.93	2.93	2.93
2026	3.29	3.29	3.29	3.29
2027	3.36	3.36	3.36	3.36
2028	3.43	3.43	3.43	3.43
2029	3.50	3.50	3.50	3.50
2030	3.56	3.56	3.56	3.56
2031	3.63	3.63	3.63	3.63
2032	3.70	3.70	3.70	3.70
2033	3.77	3.77	3.77	3.77
2034	3.84	3.84	3.84	3.84
2035	3.92	3.92	3.92	3.92
2036	3.99	3.99	3.99	3.99
2037	4.07	4.07	4.07	4.07
2038	4.16	4.16	4.16	4.16

Note:

1) CSAPR SO2 and nationwide SO2 prices are used as the SO2 market price.

2) The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, NOx Emission Allowances

	CSAPR Ozone NOx ($/Ton)			
Year	**Base Case Commodity Forecast**	**VA in RGGI Commodity Forecast**	**High Fuel Price Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2023	16,345.47	16,345.47	16345.47	16,345.47
2024	16,588.87	16,588.87	16600.51	16,571.94
2025	9,997.19	9,997.19	11181.59	7,815.38
2026	3,955.39	3,955.39	5603.47	878.98
2027	3,024.10	3,024.10	4368.15	672.02
2028	2,055.99	2,055.99	2969.77	456.89
2029	1,048.75	1,048.75	1514.86	233.05
2030	3.56	3.56	1187.86	3.56
2031	3.63	3.63	968.43	3.63
2032	3.70	3.70	739.88	3.70
2033	3.77	3.77	502.47	3.77
2034	3.84	3.84	256.02	3.84
2035	3.92	3.92	3.92	3.92
2036	3.99	3.99	3.99	3.99
2037	4.07	4.07	4.07	4.07
2038	4.16	4.16	4.16	4.16

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, NOx Emission Allowances

	CSAPR Annual NOx ($/Ton)			
Year	**Base Case Commodity Forecast**	**VA in RGGI Commodity Forecast**	**High Fuel Price Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2023	2.04	2.04	2.04	2.04
2024	2.13	2.13	2.13	2.13
2025	2.74	2.74	2.74	2.74
2026	3.28	3.28	3.28	3.28
2027	3.36	3.36	3.36	3.36
2028	3.43	3.43	3.43	3.43
2029	3.50	3.50	3.50	3.50
2030	3.56	3.56	3.56	3.56
2031	3.63	3.63	3.63	3.63
2032	3.70	3.70	3.70	3.70
2033	3.77	3.77	3.77	3.77
2034	3.84	3.84	3.84	3.84
2035	3.92	3.92	3.92	3.92
2036	3.99	3.99	3.99	3.99
2037	4.07	4.07	4.07	4.07
2038	4.16	4.16	4.16	4.16

Note: The 2023 - 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 4N: Commodity Price Forecast, CO_2

Year	Federal CO_2 ($/Ton)			
	Base Case Commodity Forecast	VA in RGGI Commodity Forecast	High Fuel Price Commodity Forecast	Low Fuel Price Case Commodity Forecast
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2033	-	-	-	-
2034	-	-	-	-
2035	-	-	-	-
2036	3.18	3.18	3.18	3.18
2037	6.49	6.49	6.49	6.49
2038	9.93	9.93	9.93	9.93

Note: CO2 prices reflect RGGI Market Price for 2023 and the federal carbon price forecast 2036 and beyo

Appendix 4N: Commodity Price Forecast, CO_2

	RGGI CO_2 ($/Ton)			
Year	**Base Case Commodity Forecast**	**VA in RGGI Commodity Forecast**	**High Fuel Price Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2023	13.27	13.27	13.27	13.27
2024	-	13.67	-	-
2025	-	9.45	-	-
2026	-	5.05	-	-
2027	-	4.70	-	-
2028	-	4.51	-	-
2029	-	4.32	-	-
2030	-	4.13	-	-
2031	-	4.29	-	-
2032	-	4.43	-	-
2033	-	4.59	-	-
2034	-	4.75	-	-
2035	-	4.92	-	-
2036	-	3.42	-	-
2037	-	-	-	-
2038	-	-	-	-

Note:

1) ICF assumes a charge on CO2 from the U.S. power sector during 2036, and it is assumed that RGGI states and CA transition from their respective programs to the national program once the national prices are higher.

2) RGGI price forecasts assume Virginia exits RGGI before January 1, 2024, except for the VA in RGGI commodity forecast, which assumes that Virginia remains in RGGI.

Appendix 4O – Delivered Fuel Data (Plan B Specific)

Company Name: Virginia Electric and Power Company **Schedule 18**

FUEL DATA

	(ACTUAL)				(PROJECTED)														
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
I. Delivered Fuel Price ($/mmBtu)(1)																			
a. Nuclear	0.59	0.58	0.58	0.56	0.56	0.57	0.58	0.59	0.58	0.56	0.56	0.58	0.64	0.67	0.70	0.74	0.78	0.81	0.86
b. Biomass	3.05	3.75	3.95	3.40	3.46	3.52	3.60	3.67	3.74	3.81	3.89	3.96	3.98	4.03	4.05	4.06	4.14	4.23	4.32
c. Coal	2.70	2.46	3.04	4.30	4.30	4.33	4.04	3.78	3.55	3.32	3.15	3.18	3.24	3.31	3.40	3.48	3.57	3.65	3.74
d. Heavy Fuel Oil	7.11	14.23	-	12.65	12.37	13.05	13.51	13.76	14.03	14.31	14.58	14.85	15.12	15.51	15.91	16.34	16.72	17.13	17.55
e. Light Fuel Oil(2)	14.15	14.25	18.31	20.90	19.25	18.64	18.72	19.08	19.44	19.83	20.21	20.58	20.96	21.34	21.74	22.16	22.59	23.04	23.50
f. Natural Gas	2.58	4.04	7.15	4.23	4.38	4.48	3.69	3.47	3.39	3.23	3.30	3.47	3.64	3.83	4.03	4.22	4.22	4.24	4.25
II. Primary Fuel Expenses (cents/kWh)(3)																			
a. Nuclear	0.60	0.60	0.58	0.58	0.58	0.59	0.61	0.61	0.60	0.58	0.58	0.60	0.66	0.70	0.73	0.77	0.81	0.85	0.89
b. Biomass	4.34	2.74	3.68	4.02	4.03	3.98	4.07	4.16	4.25	4.32	4.39	4.45	4.44	4.56	4.65	4.65	4.75	4.85	4.95
c. Coal	3.39	5.38	2.69	0.10	4.18	4.22	3.93	3.72	3.51	3.26	3.07	3.10	3.15	3.22	3.31	3.39	3.47	3.55	3.64
d. Heavy Fuel Oil	5.70	15.81	5.01	11.98	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
e. Light Fuel Oil(2)	18.41	2.91	14.87	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
f. Natural Gas	1.87	5.61	7.30	2.91	2.90	3.01	2.82	2.69	2.64	2.52	2.55	2.70	2.82	2.97	3.11	3.25	3.26	3.26	3.28
g. PPA(4)	4.57	4.71	5.73	6.83	6.78	6.79	6.76	6.72	6.69	6.77	6.88	7.03	7.18	7.33	7.48	7.65	7.81	7.99	8.15
i. Economy Energy Purchases(5)	2.82	5.13	8.64	3.83	3.80	3.94	3.85	3.07	2.94	2.96	3.00	3.10	3.30	3.41	3.56	3.84	4.10	4.35	4.61
j. Capacity Purchases ($/kW-Year)	31.49	41.52	31.84	14.20	11.35	18.83	28.68	35.31	42.20	49.37	56.76	62.45	66.88	71.45	76.20	81.15	86.22	91.44	96.86

(1) Delivered fuel price for NAPP (12,900, 3.2% FOB), No. 2 Oil, No. 6 Oil and 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) Primary Fuel Expenses for Nuclear, Biomass, Coal, Heavy Fuel Oil, and Natural Gas are based on North Anna 1, Altavista, Mount Storm 1, Yorktown 3, and Possum Point 6, respectively.

(4) Average of PPA fuel expenses.

(5) Average cost of market energy purchases.

Appendix 5A – Existing Generation Units in Service

Company Name: Virginia Electric and Power Company

Schedule 14a

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name[1]	Location	Unit Class	Primary Fuel Type	C.O.D.[3]	MW Summer
Altavista	VA	Baseload	Biomass	1992	51
Bath County 1	VA	Intermediate	Pumped Storage	1985	301
Bath County 2	VA	Intermediate	Pumped Storage	1985	301
Bath County 3	VA	Intermediate	Pumped Storage	1985	301
Bath County 4	VA	Intermediate	Pumped Storage	1985	301
Bath County 5	VA	Intermediate	Pumped Storage	1985	301
Bath County 6	VA	Intermediate	Pumped Storage	1985	301
Bear Garden	VA	Baseload/Intermediate	Natural Gas	2011	622
Brunswick	VA	Baseload/Intermediate	Natural Gas	2016	1,401
Chesapeake CT 1, 4, 6	VA	Peak	Light Oil	1967	39
Chesterfield 5[2]	VA	Baseload	Coal	1964	337
Chesterfield 6[2]	VA	Baseload	Coal	1969	678
Chesterfield 7	VA	Intermediate	Natural Gas	1990	191
Chesterfield 8	VA	Intermediate	Natural Gas	1992	195
Clover 1	VA	Intermediate	Coal	1995	220
Clover 2	VA	Intermediate	Coal	1996	219
Colonial Trail West	VA	Intermittent	Solar	2019	37
CVOW (Demonstration)	VA	Intermittent	Wind	2020	3
Darbytown 1	VA	Peak	Natural Gas	1990	85
Darbytown 2	VA	Peak	Natural Gas	1990	85
Darbytown 3	VA	Peak	Natural Gas	1990	85
Darbytown 4	VA	Peak	Natural Gas	1990	85
Elizabeth River 1	VA	Peak	Natural Gas	1992	109
Elizabeth River 2	VA	Peak	Natural Gas	1992	107
Elizabeth River 3	VA	Peak	Natural Gas	1992	109
Gaston Hydro	NC	Intermittent	Hydro	1963	220
South Anna 1	VA	Intermediate	Natural Gas	1994	104
South Anna 1	VA	Intermediate	Natural Gas	1994	104
Grassfield Solar	VA	Intermittent	Solar	2022	7
Gravel Neck 1-2	VA	Peak	Light Oil	1970	28
Gravel Neck 3	VA	Peak	Natural Gas	1989	85
Gravel Neck 4	VA	Peak	Natural Gas	1989	85
Gravel Neck 5	VA	Peak	Natural Gas	1989	85
Gravel Neck 6	VA	Peak	Natural Gas	1989	85
Greensville	VA	Baseload/Intermediate	Natural Gas	2018	1,588
Hopewell	VA	Baseload	Biomass	1989	51
Ladysmith 1	VA	Peak	Natural Gas	2001	151
Ladysmith 2	VA	Peak	Natural Gas	2001	151

Appendix 5A – Existing Generation Units in Service

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name[(1)]	Location	Unit Class	Primary Fuel Type	C.O.D.[(3)]	MW Summer
Ladysmith 3	VA	Peak	Natural Gas	2008	160
Ladysmith 4	VA	Peak	Natural Gas	2008	160
Ladysmith 5	VA	Peak	Natural Gas	2009	161
Lowmoor CT 1-4	VA	Peak	Light Oil	1971	48
Mount Storm 1	WV	Baseload	Coal	1965	544
Mount Storm 2	WV	Baseload	Coal	1966	553
Mount Storm 3	WV	Baseload	Coal	1973	520
Mount Storm CT	WV	Peak	Light Oil	1967	11
North Anna 1	VA	Baseload	Nuclear	1978	838
North Anna 2	VA	Baseload	Nuclear	1980	835
North Anna Hydro	VA	Intermittent	Hydro	1987	1
Northern Neck CT 1-4	VA	Peak	Natural Gas	1971	47
Possum Point 6	VA	Baseload/Intermediate	Natural Gas	2003	573
Possum Point CT 1-6	VA	Peak	Light Oil	1968	72
Water Strider PPA	VA	Intermittent	Solar	2021	29
Westmoreland PPA	VA	Intermittent	Solar	2021	7
Remington 1	VA	Peak	Natural Gas	2000	150
Remington 2	VA	Peak	Natural Gas	2000	151
Remington 3	VA	Peak	Natural Gas	2000	152
Remington 4	VA	Peak	Natural Gas	2000	151
Roanoke Rapids Hydro	NC	Intermittent	Hydro	1955	95
Rosemary	NC	Peak	Natural Gas	1990	155
Sadler Solar	VA	Intermittent	Solar	2021	27
Scott Solar	VA	Intermittent	Solar	2016	5
Solar Partnership Program	VA	Intermittent	Solar	2012	2
Southampton	VA	Baseload	Biomass	1992	51
Spring Grove	VA	Intermittent	Solar	2020	26
Surry 1	VA	Baseload	Nuclear	1972	838
Surry 2	VA	Baseload	Nuclear	1973	838
Sycamore Solar	VA	Intermittent	Solar	2023	14
Virginia City Hybrid Energy Center	VA	Baseload/Intermediate	Coal	2012	610
Warren	VA	Baseload/Intermediate	Natural Gas	2014	1,381
Whitehouse Solar	VA	Intermittent	Solar	2016	5
Woodland Solar	VA	Intermittent	Solar	2016	5
Yorktown 3[(2)]	VA	Peak	Heavy Oil	1974	767
Norge Solar	VA	Intermittent	Solar	2023	7
Chesapeake PPA	VA	Intermittent	Solar	2024	41
Pleasant Hill PPA	VA	Intermittent	Solar	2023	7

Appendix 5A – Existing Generation Units in Service

Company Name: Virginia Electric and Power Company

Schedule 14a

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name(1)	Location	Unit Class	Primary Fuel Type	C.O.D.(3)	MW Summer
Rivanna PPA	VA	Intermittent	Solar	2024	4
Watlington PPA	VA	Intermittent	Solar	2023	7
Wythe 2 PPA	VA	Intermittent	Solar	2024	26
Black Bear Distributed	VA	Intermittent	Solar	2024	0
Clean Energy 2 DER 2	VA	Intermittent	Solar	2023	4
Clean Energy 2 DER 3	VA	Intermittent	Solar	2023	2
Springfield Distributed	VA	Intermittent	Solar	2024	1
Cox PPA	VA	Intermittent	Solar	2024	4
Sinai PPA	VA	Intermittent	Solar	2024	3
Stratford PPA	VA	Intermittent	Solar	2023	4
Camellia Solar	VA	Intermittent	Solar	2024	5
Fountain Creek Solar	VA	Intermittent	Solar	2024	21
Otter Creek Solar	VA	Intermittent	Solar	2024	16
Piney Creek Base Solar	VA	Intermittent	Solar	2024	21
Quillwort Solar	VA	Intermittent	Solar	2024	5
Sebera Solar	VA	Intermittent	Solar	2024	5
Solidago Solar	VA	Intermittent	Solar	2023	5
Walnut Solar	VA	Intermittent	Solar	2023	40
Winterberry Solar	VA	Intermittent	Solar	2023	5
Winterpock Solar	VA	Intermittent	Solar	2024	5
Clean Energy 3 DER 1	VA	Intermittent	Solar	2024	1
Clean Energy 3 DER 2	VA	Intermittent	Solar	2024	3
Cox Storage	VA	Peak	Grid	2024	7
Sinai Storage	VA	Peak	Grid	2024	4
Dry Bridge Storage	VA	Peak	Grid	2023	18
Subtotal - Base					6,133
Subtotal - Baseload/Intermediate					6,175
Subtotal - Intermediate					2,840
Subtotal - Peak					3,587
Subtotal - Intermittent					724
Total					19,459

Note: Summer MW's for solar generation (renewables) represents firm capacity.

(1) Exisiting generators as of 2024

(2) Chesterfield 5 & 6 and Yorktown 3 are due to be retired by the end of 2023.

(3) Commercial operation date

Appendix 5B - Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Purchase Power Agreement (PPA) Units(1)					
Alexandria/Arlington - Covanta	VA	Municipal Solid Waste	21,000	1/29/1988	1/28/2023
Brasfield Dam	VA	Hydro	2,800	10/12/1993	Auto renew
Suffolk Landfill	VA	Methane	3,280	8/1/2020	3/31/2022
Columbia Mills	VA	Hydro	343	2/7/1985	Auto renew
Lakeview (Swift Creek) Dam	VA	Hydro	400	11/26/2008	Auto renew
MeadWestvaco (formerly Westvaco)	VA	Coal/Biomass	140,000	11/3/1982	8/25/2028
Banister Dam	VA	Hydro	1,785	9/28/2008	Auto renew
Weyerhaeuser/Domtar	NC	Coal/biomass	9000(2)	7/27/1991	Auto renew
Smurfit-Stone Container	VA	Coal/biomass	3500(3)	3/21/1981	Auto renew
Burnshire Dam	VA	Hydro	100	7/11/2016	Auto renew
Cushaw Hydro	VA	Hydro	2,000	11/21/2018	11/20/2033
Essex Solar Center	VA	Solar	20,000	12/14/2017	12/13/2037
Rives Road Solar	VA	Solar	19,700	5/15/2020	5/14/2033
Pamplin Solar	VA	Solar	15,700	7/13/2020	7/12/2033
Hickory Solar	VA	Solar	32,000	9/8/2020	9/7/2033
Mt Jackson I Solar	VA	Solar	15,650	6/14/2021	6/13/2034
Hollyfield II Solar	VA	Solar	13,000	7/22/2021	7/21/2034
Buckingham II Solar	VA	Solar	20,000	7/28/2021	7/27/2034
Water Strider Solar	VA	Solar	80,000	5/15/2021	5/14/2041
Westmoreland County Solar	VA	Solar	20,000	10/22/2021	10/21/2041
Tredegar Solar	VA	Solar	480	11/18/2022	11/17/2032
Nokesville Solar	VA	Solar	20,000	11/22/2022	11/21/2035
Rappahannock Solar	VA	Solar	1,500	11/24/2021	11/23/2036
W. E. Partners II	NC	Biomass	300	3/15/2012	Auto renew
Plymouth Solar	NC	Solar	5,000	10/4/2012	10/3/2027
W. E. Partners 1	NC	Biomass	100	4/26/2013	Auto renew
Dogwood Solar	NC	Solar	20,000	12/9/2014	12/8/2029
HXOap Solar	NC	Solar	20,000	12/16/2014	12/15/2029
Bethel Price Solar	NC	Solar	5,000	12/9/2014	12/8/2029
Jakana Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Lewiston Solar	NC	Solar	5,000	12/18/2014	12/17/2029
Williamston Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Windsor Solar	NC	Solar	5,000	12/17/2014	12/16/2029
510 REPP One Solar	NC	Solar	1,250	3/11/2015	3/10/2030
Everetts Wildcat Solar	NC	Solar	5,000	3/11/2015	3/10/2030
SolNC5 Solar	NC	Solar	5,000	5/12/2015	5/11/2030
Creswell Aligood Solar	NC	Solar	14,000	5/13/2015	5/12/2030
Two Mile Desert Road - SolNC1	NC	Solar	5,000	8/10/2015	8/9/2030
SolNCPower6 Solar	NC	Solar	5,000	11/1/2015	10/31/2030
Downs Farm Solar	NC	Solar	5,000	12/1/2015	11/30/2030
GKS Solar- SolNC2	NC	Solar	5,000	12/16/2015	12/15/2030
Windsor Cooper Hill Solar	NC	Solar	5,000	12/18/2015	12/17/2030

Appendix 5B - Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Purchase Power Agreement (PPA) Units[(1)]					
Green Farm Solar	NC	Solar	5,000	1/6/2016	1/5/2031
FAE X - Shawboro	NC	Solar	20,000	1/26/2016	1/25/2031
FAE XVII - Watson Seed	NC	Solar	20,000	1/28/2016	1/27/2031
Bradley PVI- FAE IX	NC	Solar	5,000	2/4/2016	2/3/2031
Conetoe Solar	NC	Solar	5,000	2/5/2016	2/4/2031
SolNC3 Solar-Sugar Run Solar	NC	Solar	5,000	2/5/2016	2/4/2031
Gates Solar	NC	Solar	5,000	2/8/2016	2/7/2031
Long Farm 46 Solar	NC	Solar	5,000	2/12/2016	2/11/2031
Battleboro Farm Solar	NC	Solar	5,000	2/17/2016	2/16/2031
Winton Solar	NC	Solar	5,000	2/8/2016	2/7/2031
SolNC10 Solar	NC	Solar	5,000	1/13/2016	1/12/2031
Tarboro Solar	NC	Solar	5,000	12/31/2015	12/30/2030
Bethel Solar	NC	Solar	4,400	3/3/2016	3/2/2031
Garysburg Solar	NC	Solar	5,000	3/18/2016	3/17/2031
Woodland Solar	NC	Solar	5,000	4/7/2016	4/6/2031
Gaston Solar	NC	Solar	5,000	4/18/2016	4/17/2031
TWE Kelford Solar	NC	Solar	4,700	6/6/2016	6/5/2031
FAE XVIII - Meadows	NC	Solar	20,000	6/9/2016	6/8/2031
Seaboard Solar	NC	Solar	5,000	6/29/2016	6/28/2031
Simons Farm Solar	NC	Solar	5,000	7/13/2016	7/12/2031
Whitakers Farm Solar	NC	Solar	3,400	7/20/2016	7/19/2031
MC1 Solar	NC	Solar	5,000	8/19/2016	8/18/2031
Williamston West Farm Solar	NC	Solar	5,000	8/23/2016	8/22/2031
River Road Solar	NC	Solar	5,000	8/23/2016	8/22/2031
White Farm Solar	NC	Solar	5,000	8/26/2016	8/25/2031
Hardison Farm Solar	NC	Solar	5,000	9/9/2016	9/8/2031
Modlin Farm Solar	NC	Solar	5,000	9/14/2016	9/13/2031
Battleboro Solar	NC	Solar	5,000	10/7/2016	10/6/2031
Williamston Speight Solar	NC	Solar	15,000	11/23/2016	11/22/2031
Barnhill Road Solar	NC	Solar	3,100	11/30/2016	11/29/2031
Hemlock Solar	NC	Solar	5,000	12/5/2016	12/4/2031
Leggett Solar	NC	Solar	5,000	12/14/2016	12/13/2031
Schell Solar Farm	NC	Solar	5,000	12/22/2016	12/21/2031
FAE XXXV - Turkey Creek	NC	Solar	13,500	1/31/2017	1/30/2027
FAE XXII - Baker PVI	NC	Solar	5,000	1/30/2017	1/29/2032
FAE XXI -Benthall Bridge PVI	NC	Solar	5,000	1/30/2017	1/29/2032
Aulander Hwy 42 Solar	NC	Solar	5,000	12/30/2016	12/29/2031
Floyd Road Solar	NC	Solar	5,000	6/19/2017	6/18/2032
Flat Meeks- FAE II	NC	Solar	5,000	10/27/2017	10/26/2032
HXNAir Solar One	NC	Solar	5,000	12/21/2017	12/20/2032
Cork Oak Solar	NC	Solar	20,000	12/29/2017	12/28/2027
Sunflower Solar	NC	Solar	16,000	12/29/2017	12/28/2027
Davis Lane Solar	NC	Solar	5,000	12/31/2017	12/30/2032

Appendix 5B - Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Purchase Power Agreement (PPA) Units(1)					
FAE XIX- American Legion PVI	NC	Solar	15,840	1/2/2018	1/1/2033
FAE XXV-Vaughn's Creek	NC	Solar	20,000	1/2/2018	1/1/2033
TWE Ahoskie Solar Project	NC	Solar	5,000	1/12/2018	1/11/2033
Cottonwood Solar	NC	Solar	3,000	1/25/2018	1/24/2033
Shiloh Hwy 1108 Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Chowan Jehu Road Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Phelps 158 Solar Farm	NC	Solar	5,000	2/26/2018	2/25/2033
Sandy Solar	NC	Solar	5,000	5/30/2018	5/29/2033
Northern Cardinal Solar	NC	Solar	2,000	6/29/2018	6/28/2033
Carl Friedrich Gauss Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Sun Farm VI Solar	NC	Solar	4,975	9/10/2018	9/9/2033
Sun Farm V Solar	NC	Solar	4,975	9/10/2018	9/9/2033
Citizens Hertford	NC	Solar	16,200	6/6/2019	6/5/2029
Camden Dam Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Mill Pond Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Jamesville Road	NC	Solar	5,000	9/10/2018	9/9/2033
North 301	NC	Solar	20,000	12/18/2019	12/17/2029
Five Forks	NC	Solar	20,000	12/23/2019	12/22/2029
Whitehurst PVI Solar	NC	Solar	10,000	3/13/2020	3/12/2035
FAE XXXIII - Grandy	NC	Solar	20,000	3/13/2020	3/12/2030
Alpha Value Solar	NC	Solar	5,000	7/9/2020	9/9/2033
FAE XXXIV - Underwood	NC	Solar	16,000	10/23/2020	10/22/2030
Highway -158 PVI	NC	Solar	9,000	11/10/2020	11/9/2030
Gliden Solar	NC	Solar	5,000	12/30/2020	9/9/2033
Sun Farm VIII	NC	Solar	3,975	12/17/2020	9/9/2033
Ryland Road Solar	NC	Solar	5,000	8/31/2021	9/9/2033
Windsor Hwy 17 Solar	NC	Solar	5,000	8/28/2021	9/9/2033
Hertford Solar	NC	Solar	10,000	8/3/2022	8/2/2027

(1) In operation as of December 31, 2022; generating facilities that have contracted directly with the Company

(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 5C – Equivalent Availability Factor for Plan B

Company Name: Virginia Electric and Power Company

Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

Unit Name	(ACTUAL) 2020	2021	2022	2023	(PROJECTED) 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Altavista	71	77	77	76	82	82	82	82	80	80	80	80	80	80	80	80	80	80	80
Bath County 1	90	97	72	58	82	81	91	91	83	83	83	83	83	83	83	83	83	83	83
Bath County 2	67	49	74	91	91	70	91	91	83	83	83	83	83	83	83	83	83	83	83
Bath County 3	81	68	95	65	91	91	69	91	83	83	83	83	83	83	83	83	83	83	83
Bath County 4	76	78	95	72	91	91	79	91	83	83	83	83	83	83	83	83	83	83	83
Bath County 5	97	77	97	89	64	91	92	91	83	83	83	83	83	83	83	83	83	83	83
Bath County 6	89	77	96	51	84	91	91	91	83	83	83	83	83	83	83	83	83	83	83
Bear Garden	87	75	73	79	87	82	88	88	83	83	83	83	83	83	83	83	83	83	83
Brunswick	88	82	69	56	86	82	86	86	82	82	82	82	82	82	82	82	82	82	82
BTM Unit 1	N/A	N/A	N/A	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM Unit 2	N/A	N/A	N/A	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM Unit 3	76	77	71	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Chesapeake CT 1, 4, 6	97	92	94	74	74	73	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	76	73	40	78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	78	43	68	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	65	64	71	79	100	100	100	92	96	96	96	96	96	96	96	96	96	96	96
Chesterfield 8	44	68	70	80	92	100	100	92	96	96	96	96	96	96	96	96	96	96	96
Clover 1	73	62	79	78	81	82	81	82	77	77	77	77	77	77	77	77	77	77	77
Clover 2	65	73	81	77	84	76	76	76	81	81	81	81	81	81	81	81	81	81	81
Darbytown 1	71	66	50	97	97	97	97	94	96	96	96	96	96	96	96	96	96	96	96
Darbytown 2	98	87	74	97	97	93	97	94	96	96	96	96	96	96	96	96	96	96	96
Darbytown 3	81	87	70	97	97	97	97	94	96	96	96	96	96	96	96	96	96	96	96
Darbytown 4	97	91	71	97	97	97	97	94	96	96	96	96	96	96	96	96	96	96	96
Elizabeth River 1	37	90	95	91	91	88	88	84	88	88	88	88	88	88	88	88	88	88	88
Elizabeth River 2	80	82	91	91	67	91	91	84	88	88	88	88	88	88	88	88	88	88	88
Elizabeth River 3	77	75	84	91	91	91	67	84	88	88	88	88	88	88	88	88	88	88	88
South Anna 1	65	86	90	79	90	96	96	96	92	92	92	92	92	92	92	92	92	92	92
South Anna 2	67	71	84	94	92	96	90	96	93	93	93	93	93	93	93	93	93	93	93
Gravel Neck 1-2	98	98	95	66	66	65	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	86	72	91	97	97	97	92	97	91	96	91	96	96	96	96	96	96	96	96
Gravel Neck 4	87	71	87	97	97	97	97	96	96	96	96	96	96	96	96	96	96	96	96
Gravel Neck 5	88	78	88	97	97	97	93	96	96	96	96	96	96	96	96	96	96	96	96
Gravel Neck 6	88	76	89	97	97	97	97	96	96	96	96	96	96	96	96	96	96	96	96
Greensville	77	87	85	77	90	87	90	90	89	89	89	89	89	89	89	89	89	89	89
Hopewell	20	76	80	77	78	78	78	87	77	77	77	77	77	77	77	77	77	77	77
Ladysmith 1	92	85	88	91	93	93	93	93	92	92	92	92	92	92	92	92	92	92	92
Ladysmith 2	92	87	72	91	93	93	93	93	92	92	92	92	92	92	92	92	92	92	92
Ladysmith 3	92	90	89	91	92	92	92	93	92	92	92	92	92	92	92	92	92	92	92
Ladysmith 4	90	88	90	91	92	92	92	93	92	92	92	92	92	92	92	92	92	92	92
Ladysmith 5	77	90	89	91	92	92	92	93	92	92	92	92	92	92	92	92	92	92	92
Lowmoor CT 1-4	98	99	95	81	83	83	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	76	59	59	76	87	85	87	85	82	82	82	82	82	82	82	82	82	82	82
Mount Storm 2	63	58	82	74	82	89	88	89	85	85	85	85	85	85	85	85	85	85	85
Mount Storm 3	58	65	62	72	84	91	89	91	87	87	87	87	87	87	87	87	87	87	87
Mount Storm CT	100	88	98	81	81	81	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear - Small Modular Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95	95	95	95	95
New Combustion Turbine_ 1	-	-	-	-	-	-	-	-	92	92	92	92	92	92	92	92	92	92	92
New Combustion Turbine_ 2	-	-	-	-	-	-	-	-	92	92	92	92	92	92	92	92	92	92	92
New Combustion Turbine_Greenfield	-	-	-	-	-	-	-	-	-	-	100	100	100	100	100	92	92	92	92
North Anna 1	100	82	89	98	90	90	98	76	88	98	89	89	98	90	90	93	93	93	-
North Anna Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	93
North Anna 2	87	100	80	90	98	90	76	98	88	89	98	88	90	98	90	93	93	93	93
North Anna Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	89	93	70	80	80	80	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	87	66	68	81	80	88	88	88	83	83	83	83	83	83	83	83	83	83	83

Appendix 5C – Equivalent Availability Factor for Plan B

Company Name: Virginia Electric and Power Company

Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Possum Point CT 1-6	100	95	87	73	73	72	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	94	90	77	91	94	94	94	94	93	93	93	93	93	93	93	93	93	93	93
Remington 2	94	90	92	91	94	94	94	94	93	93	93	93	93	93	93	93	93	93	93
Remington 3	93	92	92	85	94	94	94	94	93	93	93	93	93	93	93	93	93	93	93
Remington 4	90	90	91	76	94	94	94	94	93	93	93	93	93	93	93	93	93	93	93
Rosemary	89	82	73	80	83	83	83	78	77	77	77	77	77	77	77	77	77	77	77
Southampton	78	77	76	79	78	80	80	90	79	79	79	79	79	79	79	79	79	79	79
Surry 1	100	90	85	98	89	90	98	88	88	98	79	90	-	-	-	-	-	-	-
Surry Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	95	95	95	95	95	95	95
Surry 2	91	88	100	88	89	98	85	88	98	79	90	98	85	-	-	-	-	-	-
Surry Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	95	95	95	95	95	95
Virginia City Hybrid Energy Center	69	69	63	83	82	83	83	83	80	80	80	80	80	80	80	80	80	80	80
Warren	81	70	74	84	79	81	84	84	80	80	80	80	80	80	80	80	80	80	80
Yorktown 3	80	73	66	46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cox Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sinai Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Sisters Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dry Bridge Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dulles Tied Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hampton Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shands Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery_4H Hybrid (30MW) Post 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery_4H Hybrid (30MW) Post 2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery_4H Hybrid (30MW) Post 2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:
(1) Equivalent availability factor for intermittent resources shown as a capacity factor.

Appendix 5D – Net Capacity Factor

Company Name: Virginia Electric and Power Company — Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Altavista	66	72	75	72.2	72.0	75.0	75.0	59.9	37.2	75.0	75.0	75.0	75.0	10.3	12.7	75.0	75.0	75.0	75.0
Bath County 1	20	21	16	16.1	19.5	18.6	18.9	19.4	16.7	14.8	13.1	12.3	10.8	11.3	11.0	10.7	10.8	11.3	12.0
Bath County 2	12	8	16	21.6	18.7	12.7	15.5	17.5	17.2	15.3	13.8	12.5	11.3	11.3	11.0	10.6	9.9	10.2	9.8
Bath County 3	9	13	19	15.6	19.9	18.5	12.8	18.5	18.6	16.9	14.7	13.4	12.1	12.1	11.8	11.3	11.2	11.9	12.5
Bath County 4	12	10	23	17.9	20.1	18.2	15.8	19.2	19.0	17.0	15.2	13.7	12.4	12.5	11.9	12.1	11.4	12.4	12.7
Bath County 5	14	11	21	22.3	14.5	18.6	17.6	19.6	19.1	17.6	15.3	14.0	12.7	12.7	12.3	12.2	11.6	12.9	13.2
Bath County 6	8	8	10	14.4	20.4	20.7	20.1	19.2	21.2	19.4	16.7	15.2	14.0	14.2	13.6	13.5	13.5	15.0	15.7
Bear Garden	78	57	44	70.5	71.3	68.9	84.9	83.1	76.2	74.2	71.6	72.1	74.7	68.3	69.9	72.1	76.2	78.8	79.4
Brunswick	82	72	60	53.6	80.6	77.5	82.7	82.3	77.2	76.2	75.8	76.6	77.6	74.9	74.7	75.9	77.6	77.8	77.8
Existing VA Solar PPAS 2020	-	-	-	25.4	25.4	25.4	25.5	25.4	25.4	25.4	25.5	25.4	25.4	25.4	25.5	25.4	25.4	25.4	25.5
BTM Unit 1	N/A	N/A	N/A	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
BTM Unit 2	N/A	N/A	N/A	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
BTM Unit 3	76	77	71	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
Grassfield Solar	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Norge Solar	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Cavalier PPA	-	-	-	-	-	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3
Chesapeake PPA	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Pleasant Hill PPA	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Rivanna PPA	-	-	-	-	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Watlington PPA	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Wythe 2 PPA	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Sycamore Solar	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Black Bear Distributed	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Clean Energy 2 DER 2	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Clean Energy 2 DER 3	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Springfield Distributed	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
360 PPA	-	-	-	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Cox PPA	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Ho Fel PPA	-	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Sinai PPA	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Stratford PPA	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Surry PPA	-	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Camellia Solar	-	-	-	-	20.1	20.2	20.2	20.2	20.1	20.2	20.2	20.2	20.1	20.2	20.2	20.2	20.1	20.2	20.2
Dulles Tied Solar	-	-	-	-	-	-	19.8	19.8	19.7	19.8	19.8	19.8	19.7	19.8	19.8	19.8	19.7	19.8	19.8
Fountain Creek Solar	-	-	-	-	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1
Otter Creek Solar	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Piney Creek Base Solar	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Quillwort Solar	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Sebera Solar	-	-	-	-	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Solidago Solar	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Sweet Sue Solar	-	-	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Walnut Solar	-	-	-	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Winterberry Solar	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Winterpock Solar	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Augusta PPA	-	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Clean Energy 3 DER 1	-	-	-	-	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Clean Energy 3 DER 2	-	-	-	-	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
Pivot Energy VA 2	-	-	-	-	-	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
Groves PPA	-	-	-	-	-	-	-	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Harrisonburg PPA	-	-	-	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Jarratt PPA	-	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Switchgrass PPA	-	-	-	-	-	20.8	20.8	20.8	20.9	20.8	20.8	20.8	20.9	20.8	20.8	20.8	20.9	20.8	20.8
Bridleton Solar	-	-	-	-	-	-	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Chesapeake CT 1, 4, 6	0	0	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	21	18	16	36.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	17	10	16	32.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	69	56	56	72.4	89.0	89.2	90.1	82.8	85.5	85.8	86.0	86.5	86.6	85.3	84.8	85.8	86.6	86.4	86.4
Chesterfield 8	39	61	57	72.9	82.5	89.0	90.3	82.7	85.5	84.8	84.6	86.3	86.0	83.1	83.1	84.5	86.3	86.6	86.6
Clover 1	17	11	8	24.8	19.3	16.1	13.8	14.0	16.4	14.0	15.6	19.5	21.3	21.5	25.1	31.4	26.5	25.0	25.9
Clover 2	16	12	8	26.6	20.2	18.1	17.1	16.4	19.3	15.9	18.9	22.3	25.0	24.8	30.3	35.4	33.6	31.4	34.3
Darbytown 1	1	1	1	5.0	0.9	2.7	4.1	2.5	2.1	1.9	1.7	1.7	1.7	1.8	1.7	1.8	1.9	1.7	1.6
Darbytown 2	4	1	2	5.0	0.8	2.6	4.1	2.5	2.0	1.9	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.7	1.6

Appendix 5D – Net Capacity Factor

Company Name: Virginia Electric and Power Company

Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

Unit Name	2020 (ACTUAL)	2021 (ACTUAL)	2022 (ACTUAL)	2023 (PROJECTED)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Darbytown 3	3	3	1	5.0	0.9	2.7	4.1	2.5	2.0	1.9	1.6	1.7	1.6	1.7	1.7	1.7	1.9	1.7	1.6
Darbytown 4	7	2	3	5.0	0.8	2.6	4.0	2.4	2.0	1.9	1.6	1.6	1.6	1.7	1.6	1.7	1.8	1.6	1.6
Elizabeth River 1	1	1	1	3.0	1.2	2.5	3.0	2.1	1.5	1.4	1.3	1.3	1.2	1.2	1.3	1.4	1.4	1.2	1.3
Elizabeth River 2	1	3	4	3.0	1.1	2.4	3.0	2.2	1.4	1.4	1.2	1.3	1.2	1.2	1.3	1.3	1.4	1.2	1.2
Elizabeth River 3	7	1	1	3.0	1.2	2.5	3.0	2.2	1.5	1.4	1.2	1.3	1.2	1.2	1.3	1.4	1.4	1.2	1.2
South Anna 1	60	59	58	58.6	46.2	57.1	74.2	62.7	53.2	51.8	44.5	43.3	45.6	41.8	43.6	46.5	52.7	60.5	66.3
South Anna 2	62	46	49	69.1	46.3	55.3	67.8	60.6	50.6	48.4	41.3	40.7	42.2	37.8	39.6	43.3	49.2	58.0	64.0
Gravel Neck 1-2	0	0	1	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	2	2	2	2.4	0.7	2.2	3.3	2.0	1.2	1.2	1.2	1.2	1.2	1.0	1.1	1.1	1.2	1.1	1.2
Gravel Neck 4	4	0	1	2.4	0.7	2.2	3.3	2.0	1.2	1.2	1.2	1.2	1.2	1.0	1.1	1.1	1.2	1.1	1.2
Gravel Neck 5	6	1	1	2.5	0.7	2.2	3.3	2.0	1.2	1.3	1.2	1.2	1.1	1.1	1.1	1.2	1.2	1.1	1.2
Gravel Neck 6	7	0	1	2.3	0.7	2.2	3.3	1.9	1.2	1.1	1.2	1.1	1.1	1.0	1.1	1.1	1.2	1.1	1.2
Greensville	77	83	80	74.1	86.9	84.6	87.9	88.0	86.0	86.0	86.0	85.9	85.9	85.9	85.9	85.9	86.0	85.9	85.9
Hopewell	17	69	80	75.0	64.0	75.0	75.0	51.8	29.3	74.6	74.6	74.6	74.6	6.3	9.1	74.6	74.6	74.6	74.6
Ladysmith 1	11	6	11	5.0	5.0	5.0	5.0	5.0	5.0	4.2	3.2	3.3	3.0	3.0	3.5	3.6	3.7	5.0	5.0
Ladysmith 2	19	7	14	5.0	5.0	5.0	5.0	5.0	5.0	4.3	3.3	3.4	3.1	3.0	3.5	3.7	3.8	5.0	5.0
Ladysmith 3	20	5	10	5.0	5.0	5.0	5.0	5.0	5.0	4.5	3.5	3.6	3.4	3.3	3.7	3.9	4.0	5.0	5.0
Ladysmith 4	24	10	18	23.3	13.0	15.3	16.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Ladysmith 5	10	7	11	35.0	13.1	15.8	21.6	14.4	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	15.7
Lowmoor CT 1-4	0	0	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	47	35	30	37.1	31.1	38.2	42.0	28.9	28.3	25.3	27.2	31.4	35.4	35.9	42.0	49.0	47.1	47.7	48.7
Mount Storm 2	29	38	36	38.6	33.0	41.5	43.3	30.9	29.7	27.2	29.9	34.7	39.9	40.1	46.6	53.9	50.3	51.4	52.2
Mount Storm 3	23	44	32	36.3	35.9	44.8	46.8	33.9	31.3	29.6	30.6	35.4	40.3	40.5	47.0	54.3	53.9	55.1	56.4
Mount Storm CT	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear - Small Modular Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.6	90.6	90.6	90.6	90.6
New Combustion Turbine_ 1	-	-	-	-	-	-	-	-	13.8	12.0	8.0	8.1	8.2	7.0	8.1	9.3	12.2	16.0	19.2
New Combustion Turbine_ 2	-	-	-	-	-	-	-	-	13.2	10.8	7.4	7.4	7.6	6.4	7.4	8.6	11.3	14.0	18.1
New Combustion Turbine_Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.9	9.2	11.8	15.2
North Anna 1	102	83	90	96.3	88.7	88.2	96.3	75.1	86.1	96.3	87.0	87.1	96.3	88.1	88.2	91.4	91.4	91.4	-
North Anna Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91.4
North Anna 2	88	102	82	88.3	96.4	88.2	74.8	96.4	86.1	87.2	96.4	86.8	88.3	96.4	88.1	91.2	91.2	91.2	91.2
North Anna Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	2	1	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	74	46	35	65.5	56.8	65.9	75.8	72.7	63.2	61.2	56.3	56.3	58.8	54.5	56.1	58.0	63.0	67.1	69.4
Possum Point CT 1-6	0	0	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	16	12	15	5.0	5.0	5.0	5.0	5.0	4.5	3.1	2.6	2.3	2.4	2.5	2.5	2.7	2.9	3.5	5.0
Remington 2	12	6	11	5.0	5.0	5.0	5.0	5.0	4.2	2.8	2.6	2.3	2.4	2.4	2.5	2.7	2.9	3.6	4.3
Remington 3	14	11	16	15.4	6.3	8.6	11.6	7.4	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	6.4
Remington 4	10	8	11	23.1	5.8	9.1	16.4	11.0	7.4	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.7	7.2
Rosemary	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	1.0	1.0
Southampton	61	71	75	75.0	65.2	75.0	75.0	56.8	32.4	75.0	75.0	75.0	75.0	7.3	10.6	75.0	75.0	75.0	75.0
Surry 1	102	90	87	95.9	87.5	87.6	95.9	86.7	86.3	95.9	77.7	87.6	-	-	-	-	-	-	-
Surry Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	93.0	93.0	93.0	93.0	93.0	93.0	93.0
Surry 2	92	89	102	86.7	87.1	95.9	83.8	86.3	95.9	77.7	87.6	95.9	83.5	-	-	-	-	-	-
Surry Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	93.0	93.0	93.0	93.0	93.0	93.0
Virginia City Hybrid Energy Center	16	18	26	29.5	24.5	27.1	24.1	18.6	19.7	14.9	13.0	16.4	17.5	17.7	21.2	26.0	23.1	24.6	26.0
Warren	76	60	65	80.9	75.7	78.2	80.7	80.5	75.9	75.5	75.6	75.9	75.5	73.1	73.0	74.2	75.2	75.9	76.1
Yorktown 3	1	1	0	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cox Storage	-	-	-	-	13.7	13.4	13.8	14.6	14.6	14.4	14.6	14.9	15.0	15.2	15.3	15.2	15.4	15.5	15.3
Sinai Storage	-	-	-	-	13.7	13.4	13.8	14.6	14.7	14.6	14.7	15.0	15.1	15.1	15.3	15.5	15.4	15.7	15.4
Three Sisters Storage	-	-	-	-	-	16.5	16.3	16.4	16.5	16.2	16.2	16.1	16.2	16.0	16.0	16.0	16.0	15.9	15.5
Dry Bridge Storage	-	-	-	16.4	15.8	16.2	15.8	15.9	16.1	15.6	15.3	14.7	14.9	14.4	14.0	13.7	13.6	13.4	12.6
Dulles Tied Storage	-	-	-	-	-	-	7.0	8.1	8.3	7.9	7.7	8.2	8.6	9.2	9.0	9.2	9.5	9.9	9.5
Cedar Storage	-	-	-	-	-	16.2	15.9	16.1	16.3	15.8	15.8	15.8	15.8	15.5	15.2	15.3	14.8	14.1	13.0
Hampton Storage	-	-	-	-	-	16.2	15.9	16.1	16.3	15.8	15.8	15.8	15.8	15.5	15.2	15.2	14.8	14.1	13.0
Shands Storage	-	-	-	-	-	-	15.8	15.9	16.1	15.6	15.2	14.7	14.9	14.4	14.0	13.7	13.6	13.4	12.6
Battery_4H Hybrid (30MW) Post 2027	-	-	-	-	-	-	-	-	-	-	15.6	15.4	15.5	15.1	14.8	14.8	14.9	14.9	14.1
Battery_4H Hybrid (30MW) Post 2028	-	-	-	-	-	-	-	-	16.3	15.8	15.5	15.1	15.3	14.7	14.4	14.2	14.3	14.0	13.1
Battery_4H Hybrid (30MW) Post 2029	-	-	-	-	-	-	-	-	-	15.8	15.6	15.2	15.4	14.9	14.5	14.5	14.5	14.2	13.3

Appendix 5E – Heat Rates

Company Name: Virginia Electric and Power Company

Schedule 1(

UNIT PERFORMANCE DATA
Average Heat Rate - (mmBtu/MWh)

	(ACTUAL)			(PROJECTED)															
Unit Name	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Altavista	15.81	16.39	16.56	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
Bath County 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden	7.19	7.31	7.27	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08
Brunswick	6.97	7.04	7.02	6.87	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86
BTM Unit 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM Unit 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM Unit 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 4, 6	15.99	18.18	16.45	14.95	14.95	14.95	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	10.46	10.36	10.30	9.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	10.40	10.25	10.18	10.14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	7.39	7.69	7.76	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
Chesterfield 8	7.36	7.36	7.73	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	10.91	11.46	11.16	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49
Clover 2	10.27	11.20	10.97	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40
Darbytown 1	12.91	13.28	12.58	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26
Darbytown 2	12.47	12.89	12.49	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26
Darbytown 3	12.54	12.90	12.44	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26
Darbytown 4	12.64	12.88	12.74	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26	12.26
Elizabeth River 1	12.50	12.55	12.32	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22
Elizabeth River 2	12.66	12.63	12.99	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22
Elizabeth River 3	12.35	12.16	12.21	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22	12.22
South Anna 1	8.29	8.14	8.63	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48
South Anna 2	8.44	8.36	8.35	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49
Gravel Neck 1-2	18.20	19.24	15.72	17.08	17.08	17.08	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	12.95	13.14	12.99	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86
Gravel Neck 4	13.12	13.21	12.76	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86
Gravel Neck 5	13.40	13.60	13.53	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86
Gravel Neck 6	12.92	13.09	13.26	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86	12.86
Greensville	6.60	6.72	6.51	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61	6.61
Hopewell	18.22	17.39	16.53	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88
Ladysmith 1	9.84	10.90	10.06	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32
Ladysmith 2	9.59	10.67	9.71	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30	10.30
Ladysmith 3	9.70	10.16	9.67	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27
Ladysmith 4	9.62	10.18	9.90	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27
Ladysmith 5	9.65	10.00	9.55	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28
Lowmoor CT 1-4	18.92	17.24	18.00	15.98	15.98	15.98	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	10.41	10.32	10.49	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73
Mount Storm 2	10.20	10.31	10.51	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69
Mount Storm 3	11.08	9.83	10.94	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54
Mount Storm CT	15.37	13.99	14.68	14.68	14.68	14.68	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear - Small Modular Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.72	11.72	11.72	11.72	11.72
New Combustion Turbine_ 1	-	-	-	-	-	-	-	-	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
New Combustion Turbine_ 2	-	-	-	-	-	-	-	-	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
New Combustion Turbine_Greenfield	-	-	-	-	-	-	-	-	-	-	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
North Anna 1	10.39	10.40	10.35	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	-
North Anna Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.40
North Anna 2	10.34	10.35	10.38	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42
North Anna Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	18.56	17.05	16.72	17.58	17.58	17.58	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	-	-	-	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77
Possum Point CT 1-6	7.15	7.15	7.50	16.21	16.21	16.21	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	9.87	10.06	9.70	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51	10.51
Remington 2	9.86	10.32	10.33	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52	10.52
Remington 3	9.72	10.22	10.33	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47	10.47
Remington 4	9.97	10.42	10.42	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54	10.54
Rosemary	10.22	9.74	11.28	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
Southampton	16.95	17.47	17.08	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19

Appendix 5E – Heat Rates

Company Name: Virginia Electric and Power Company

Schedule 1

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

	(ACTUAL)			(PROJECTED)															
Unit Name	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Surry 1	10.33	10.32	10.29	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	-	-	-	-	-	-	-
Surry Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Surry 2	10.25	10.23	10.30	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	-	-	-	-	-	-
Surry Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	10.31	10.31	10.31	10.31	10.31	10.31
Virginia City Hybrid Energy Center	12.47	10.98	10.46	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98
Warren	6.88	6.89	6.90	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08
Yorktown 3	10.91	11.11	10.21	9.08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cox Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sinai Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Sisters Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dry Bridge Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dulles Tied Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hampton Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shands Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery_4H Hybrid (30MW) Post 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery_4H Hybrid (30MW) Post 2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery_4H Hybrid (30MW) Post 2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 5F – Existing Capacity (for Plan B)

Company Name: Virginia Electric and Power Company

CAPACITY DATA

Schedule 7

	(ACTUAL)				(PROJECTED)														
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
I. Firm Capacity (MW)(1)(4)																			
a. Nuclear(5)	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. Biomass(3)	153	153	153	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214
c. Coal	3,684	3,684	3,680	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604	2,604
d. Heavy Fuel Oil	789	787	787	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil	584	584	584	245	245	-	-	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Natural Gas-Combined Cycle	6,293	6,266	6,266	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313	6,313
h. Natural Gas-Turbine	2,051	2,051	2,051	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391	2,391
i. Hydro-Conventional	317	317	317	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
j. Pumped Storage & Battery	1,809	1,809	1,809	1,840	1,840	1,840	1,840	1,840	1,840	1,839	1,839	1,838	1,838	1,837	1,837	1,836	1,836	1,835	1,835
k. Renewable	72	128	224	720	1,112	1,128	1,048	970	807	711	655	567	492	475	458	441	432	424	416
l. Total Company Firm Capacity	19,109	19,137	19,228	17,992	18,384	18,155	18,075	17,997	17,834	17,737	17,681	17,593	17,517	17,500	17,483	17,465	17,455	17,447	17,438
m. Other (PPA)	-	-	64	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224
n. Storage PPA	-	-	-	-	11	10	10	11	12	12	13	13	13	13	13	12	12	12	12
o. Renewable PPA	-	-	-	70	166	167	163	160	153	149	147	143	140	139	138	138	137	137	137
p. Total	19,109	19,137	19,293	18,286	18,784	18,556	18,472	18,392	18,223	18,122	18,064	17,972	17,894	17,875	17,857	17,839	17,828	17,819	17,810
II. Firm Capacity Mix (%)(2)																			
a. Nuclear	17.6%	17.5%	17.4%	18.3%	17.8%	18.0%	18.1%	18.2%	18.4%	18.5%	18.5%	18.6%	18.7%	18.7%	18.8%	18.8%	18.8%	18.8%	18.8%
b. Biomass(3)	0.8%	0.8%	0.8%	1.2%	1.1%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
c. Coal	19.3%	19.3%	19.1%	14.2%	13.9%	14.0%	14.1%	14.2%	14.3%	14.4%	14.4%	14.5%	14.6%	14.6%	14.6%	14.6%	14.6%	14.6%	14.6%
d. Heavy Fuel Oil	4.1%	4.1%	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%	0.0%	0.0%	0.0%	0.0%
e. Light Fuel Oil	3.1%	3.1%	3.0%	1.3%	1.3%	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-Boiler	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%
g. Natural Gas-Combined Cycle	32.9%	32.7%	32.5%	34.5%	33.6%	34.0%	34.2%	34.3%	34.6%	34.8%	34.9%	35.1%	35.3%	35.3%	35.4%	35.4%	35.4%	35.4%	35.4%
h. Natural Gas-Turbine	10.7%	10.7%	10.6%	13.1%	12.7%	12.9%	12.9%	13.0%	13.1%	13.2%	13.2%	13.3%	13.4%	13.4%	13.4%	13.4%	13.4%	13.4%	13.4%
i. Hydro-Conventional	1.7%	1.7%	1.6%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
j. Pumped Storage & Battery	9.5%	9.5%	9.4%	10.1%	9.8%	9.9%	10.0%	10.0%	10.1%	10.1%	10.2%	10.2%	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%
k. Renewable	0.4%	0.7%	1.2%	3.9%	5.9%	6.1%	5.7%	5.3%	4.4%	3.9%	3.6%	3.2%	2.8%	2.7%	2.6%	2.5%	2.4%	2.4%	2.3%
l. Total Company Firm Capacity	100.0%	100.0%	99.7%	98.4%	97.9%	97.8%	97.9%	97.9%	97.9%	97.9%	97.9%	97.9%	97.9%	97.9%	97.9%	97.9%	97.9%	97.9%	97.9%
m. Other (PPA)	0.0%	0.0%	0.3%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%
n. Storage PPA	0.0%	0.0%	0.0%	0.0%	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%
o. Renewable PPA	0.0%	0.0%	0.0%	0.4%	0.9%	0.9%	0.9%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
p. 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 annual firm capability during peak season.
(2) Each item in Section I as a percent of line "p." (Total).
(3) Includes current estimates for renewable capacity by VCHEC.
(4) Firm capacity as of model date 2024.
(5) Including nuclear extensions.

Appendix 5G – Energy Generation by Type (GWh) for Plan B

Company Name: Virginia Electric and Power Company

Schedule 2

GENERATION

	(ACTUAL)				(PROJECTED)														
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
I. System Output (GWh)																			
a. Nuclear	28,287	26,788	26,542	27,993	27,483	27,436	26,757	26,251	27,091	27,217	26,571	27,253	27,592	28,231	29,742	30,217	32,435	32,344	34,472
b. Biomass [1]	788	1,055	1,135	1,207	1,084	1,207	1,191	894	575	1,138	1,128	1,147	1,156	210	269	1,199	1,187	1,191	1,199
c. Coal	7,720	7,893	7,612	9,063	6,769	7,947	8,100	5,977	5,948	5,241	5,504	6,465	7,311	7,335	8,601	10,090	9,557	9,672	9,967
d. Heavy Fuel Oil	78	49	31	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil	38	130	271	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Natural Gas-Combined Cycle	40,819	35,685	33,087	40,685	45,317	45,529	48,878	48,014	45,520	44,929	44,293	44,501	45,027	43,439	43,626	44,303	45,474	46,048	46,355
h. Natural Gas-Turbine	2,167	997	1,537	2,316	1,120	1,437	1,804	1,360	2,404	2,086	1,675	1,674	1,681	1,559	1,683	2,175	2,944	4,074	5,710
i. Hydro-Conventional	778	661	363	627	629	627	627	627	629	627	627	627	629	627	627	627	629	627	627
j. Pumped Storage & Battery	2,005	1,854	2,772	2,906	3,046	2,891	2,820	3,165	3,213	3,021	2,826	2,765	2,736	2,938	3,048	3,241	3,459	3,843	4,039
k. Renewable	412	804	786	1,312	1,885	2,102	3,056	13,340	15,096	15,904	16,842	18,283	19,593	30,322	31,744	32,966	34,305	35,579	36,782
l. Total Generation	83,091	75,917	74,137	86,193	87,333	89,176	93,234	99,629	100,477	100,163	99,467	102,715	105,725	114,660	119,339	124,818	129,990	133,379	139,154
m. Purchased Power (PPAs)	2,314	2,711	2,718	1,875	2,344	3,178	3,171	3,740	4,209	4,664	5,170	5,838	6,522	7,166	7,825	8,483	9,162	9,787	10,435
n. Purchased Power (Battery Storage)	-	-	-	-	16	114	108	108	153	206	276	356	445	543	639	761	903	1,034	1,108
o. Purchased Power (Market / PJM)	3,946	12,747	19,846	13,545	13,829	12,661	14,446	12,771	13,935	16,193	20,495	21,103	23,491	20,009	21,662	23,275	26,037	29,956	33,076
p. Less Pumping Energy	(2,464)	(2,369)	(3,446)	(3,634)	(3,818)	(3,724)	(3,646)	(4,062)	(4,166)	(3,967)	(3,799)	(3,813)	(3,849)	(4,175)	(4,428)	(4,788)	(5,217)	(5,800)	(6,121)
q. Less Other Sales [2]	-	-	-	(2,983)	(818)	(1,200)	(1,119)	(2,735)	(1,300)	(570)	(493)	(508)	(621)	(1,085)	(1,250)	(1,397)	(1,442)	(1,263)	(1,225)
s. Total System Firm Energy Req.	86,887	89,006	93,256	94,996	98,886	100,205	106,193	109,451	113,308	116,689	121,115	125,692	131,712	137,118	143,789	151,151	159,434	167,093	176,427
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) Includes current estimates for renewable energy generation by VCHEC.

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

Appendix 5H – Energy Generation by Type (%) for Plan B

Company Name: Virginia Electric and Power Company

GENERATION

Schedule 3

	(ACTUAL)				(PROJECTED)														
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
III. System Output Mix (%)																			
a. Nuclear	32.6%	30.1%	28.5%	29.5%	27.8%	27.4%	25.2%	24.0%	23.9%	23.3%	21.9%	21.7%	20.9%	20.6%	20.7%	20.0%	20.3%	19.4%	19.5%
b. Biomass(1)	0.9%	1.2%	1.2%	1.3%	1.1%	1.2%	1.1%	0.8%	0.5%	1.0%	0.9%	0.9%	0.9%	0.2%	0.2%	0.8%	0.7%	0.7%	0.7%
c. Coal	8.9%	8.9%	8.2%	9.5%	6.8%	7.9%	7.6%	5.5%	5.2%	4.5%	4.5%	5.1%	5.6%	5.3%	6.0%	6.7%	6.0%	5.8%	5.6%
d. Heavy Fuel Oil	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Light Fuel Oil	0.0%	0.1%	0.3%	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-Boiler	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%
g. Natural Gas-Combined Cycle	47.0%	40.1%	35.5%	42.8%	45.8%	45.4%	46.0%	43.9%	40.2%	38.5%	36.6%	35.4%	34.2%	31.7%	30.3%	29.3%	28.5%	27.6%	26.3%
h. Natural Gas-Turbine	2.5%	1.1%	1.6%	2.4%	1.1%	1.4%	1.7%	1.2%	2.1%	1.8%	1.4%	1.3%	1.3%	1.1%	1.2%	1.4%	1.8%	2.4%	3.2%
i. Hydro-Conventional	0.9%	0.7%	0.4%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%
j. Pumped Storage & Battery	2.3%	2.1%	3.0%	3.1%	3.1%	2.9%	2.7%	2.9%	2.8%	2.6%	2.3%	2.2%	2.1%	2.1%	2.1%	2.1%	2.2%	2.3%	2.3%
k. Renewable	0.5%	0.9%	0.8%	1.4%	1.9%	2.1%	2.9%	12.2%	13.3%	13.6%	13.9%	14.5%	14.9%	22.1%	22.1%	21.8%	21.5%	21.3%	20.8%
l. Total Generation	95.6%	85.3%	79.5%	90.7%	88.3%	89.0%	87.8%	91.0%	88.7%	85.8%	82.1%	81.7%	80.3%	83.6%	83.0%	82.6%	81.5%	79.8%	78.9%
m. Purchased Power (PPAs)	2.7%	3.0%	2.9%	2.0%	2.4%	3.2%	3.0%	3.4%	3.7%	4.0%	4.3%	4.6%	5.0%	5.2%	5.4%	5.6%	5.7%	5.9%	5.9%
n. Purchased Power (Battery Storage)	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%	0.5%	0.6%	0.6%	0.6%
o. Purchased Power (Market / PJM)	4.5%	14.3%	21.3%	14.3%	14.0%	12.6%	13.6%	11.7%	12.3%	13.9%	16.9%	16.8%	17.8%	14.6%	15.1%	15.4%	16.3%	17.9%	18.7%
p. Less Pumping Energy	-2.8%	-2.7%	-3.7%	-3.8%	-3.9%	-3.7%	-3.4%	-3.7%	-3.7%	-3.4%	-3.1%	-3.0%	-2.9%	-3.0%	-3.1%	-3.2%	-3.3%	-3.5%	-3.5%
q. Less Other Sales(3)	0.0%	0.0%	0.0%	-3.1%	-0.8%	-1.2%	-1.1%	-2.5%	-1.1%	-0.5%	-0.4%	-0.4%	-0.5%	-0.8%	-0.9%	-0.9%	-0.9%	-0.8%	-0.7%
r. Total System Firm Energy Req.	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	56.7%	60.0%	58.5%	63.8%	65.2%	65.9%	67.3%	68.1%	68.9%	69.6%	70.5%	71.3%	72.3%	73.1%	73.8%	74.7%	75.4%	76.1%	76.9%

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

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

Appendix 5I - Solar and Wind Generating Facilities Since July 1, 2018

Project Name	Status	Nameplate (MWac)	In Service Date	Type	Cost Recovery Mechanism
Hollyfield Solar	Operational	17	2018	Company-build	Ring-Fence
Montross Solar	Operational	20	2018	Company-build	Ring-Fence
Pecan Solar	Operational	74.9	2018	Company-build	Ring-Fence
Puller Solar	Operational	15	2018	Company-build	Ring-Fence
Colonial Trail West Solar	Operational	142	2019	Company-build	RAC
Gloucester Solar	Operational	20	2019	Company-build	Ring-Fence
Gutenberg Solar	Operational	80	2019	Company-build	Ring-Fence
Chestnut Solar	Operational	75	2020	Company-build	Ring-Fence
Coastal VA Offshore Wind (CVOW) Demonstration	Operational	12	2020	Company-build	Fuel / Base
Grasshopper Solar	Operational	80	2020	Company-build	Ring-Fence
Spring Grove 1 Solar	Operational	98	2020	Company-build	RAC
Hickory Solar*	Operational	32	2020	PPA	Fuel / Base
Pamplin Solar*	Operational	15.7	2020	PPA	Fuel / Base
Rives Road Solar*	Operational	20	2020	PPA	Fuel / Base
Bedford Solar	Operational	70	2021	Company-build	Ring-Fence
Belcher Solar	Operational	88	2021	Company-build	Ring-Fence
Rochambeau Solar	Operational	20	2021	Company-build	Ring-Fence
Sadler Solar	Operational	100	2021	Company-build	RAC
Buckingham Solar II*	Operational	20	2021	PPA	Fuel / Base
Hollyfield Solar II*	Operational	13	2021	PPA	Fuel / Base
Mount Jackson Solar I*	Operational	15.65	2021	PPA	Fuel / Base
Water Strider Solar	Operational	80	2021	PPA	Fuel / Base
Westmoreland Solar	Operational	20	2021	PPA	Fuel / Base
Acorn Solar	Operational	1.4	2022	Company-build	Ring-Fence
Fort Powhatan Solar	Operational	150	2022	Company-build	Ring-Fence
Grassfield Solar	Operational	20	2022	Company-build	RAC
Maplewood Solar	Operational	120	2022	Company-build	Ring-Fence
Pumpkinseed Solar	Operational	59.6	2022	Company-build	Ring-Fence
Nokesville Solar*	Operational	20	2022	PPA	Fuel / Base
Sycamore Solar	Operational	42.0	2023	Company-build	RAC
Ivy Landfill Distributed	Under Construction	3.0	2025 (proj.)	Company-build	RAC
Black Bear Distributed	Under Construction	1.6	2023 (proj.)	Company-build	RAC
Bookers Mill Solar	Under Construction	127.0	2023 (proj.)	Company-build	Ring-Fence
Camellia Solar	Under Construction	20.0	2023 (proj.)	Company-build	RAC
Fountain Creek Solar	Under Construction	80.0	2023 (proj.)	Company-build	RAC
Norge Solar	Under Construction	20.0	2023 (proj.)	Company-build	RAC
Otter Creek Solar	Under Construction	60.0	2023 (proj.)	Company-build	RAC
Piney Creek Solar	Under Construction	80.0	2023 (proj.)	Company-build	RAC
Quillwort Solar	Under Construction	18.0	2023 (proj.)	Company-build	RAC
Sebera Solar	Under Construction	18.0	2023 (proj.)	Company-build	RAC
Solidago Solar	Under Construction	20.0	2023 (proj.)	Company-build	RAC
Springfield Distributed	Under Construction	2.0	2023 (proj.)	Company-build	RAC
Sweet Sue Solar	Under Construction	73.0	2023 (proj.)	Company-build	RAC
Winterberry Solar	Under Construction	20.0	2023 (proj.)	Company-build	RAC
Winterpock Solar	Under Construction	20.0	2023 (proj.)	Company-build	RAC
Aditya Solar*	Under Construction	11	2023 (proj.)	PPA	Fuel / Base
Chesapeake Solar	Under Construction	118	2023 (proj.)	PPA	RAC
Endless Caverns Solar*	Under Construction	31.4	2023 (proj.)	PPA	Fuel / Base
Pleasant Hill Solar	Under Construction	20	2023 (proj.)	PPA	RAC
Stratford Solar	Under Construction	15	2023 (proj.)	PPA	RAC
Watlington Solar	Under Construction	20	2023 (proj.)	PPA	RAC
Bridleton Solar	Under Construction	20.0	2024 (proj.)	Company-build	RAC
Kings Creek Solar	Under Construction	20.0	2024 (proj.)	Company-build	RAC
North Ridge Solar	Under Construction	20.0	2024 (proj.)	Company-build	RAC
Racefield Distributed	Under Construction	3.0	2024 (proj.)	Company-build	RAC
Southern Virginia Solar	Under Construction	125.0	2024 (proj.)	Company-build	RAC
Walnut Solar	Under Construction	149.9	2024 (proj.)	Company-build	RAC
Augusta Solar	Under Construction	105	2024 (proj.)	PPA	RAC
Cox Solar	Under Construction	16	2024 (proj.)	PPA	RAC
Sinai Solar	Under Construction	9.9	2024 (proj.)	PPA	RAC
Ho-Fel Solar	Under Construction	50	2024 (proj.)	PPA	RAC
Jarratt Solar	Under Construction	48.4	2024 (proj.)	PPA	RAC
New Kent Solar*	Under Construction	20	2024 (proj.)	PPA	Fuel / Base
Rivanna Solar	Under Construction	12.5	2024 (proj.)	PPA	RAC

Appendix 5I - Solar and Wind Generating Facilities Since July 1, 2018

Project Name	Status	Nameplate (MWac)	In Service Date	Type	Cost Recovery Mechanism
Surry Solar	Under Construction	20	2024 (proj.)	PPA	RAC
Switchgrass Solar	Under Construction	69	2024 (proj.)	PPA	RAC
Wythe Solar	Under Construction	75	2024 (proj.)	PPA	RAC
Dulles Solar	Under Construction	100.0	2025 (proj)	Company-build	RAC
Cavalier Solar	Under Construction	240	2025 (proj)	PPA	RAC
Cerulean Solar	Under Construction	62.0	2026 (proj.)	Company-build	RAC
Coastal VA Offshore Wind (CVOW)	Under Construction	2587	2026 (proj.)	Company-build	RAC
Courthouse Solar	Under Construction	167.0	2026 (proj.)	Company-build	RAC
Moon Corner Solar	Under Construction	60.0	2026 (proj.)	Company-build	RAC
360 Solar 1 Solar	Under Construction	26	2026 (proj.)	PPA	RAC
360 Solar 2 Solar	Under Construction	26	2026 (proj.)	PPA	RAC
Groves Solar	Under Construction	16.2	2026 (proj.)	PPA	RAC
Harrisonburg Solar	Under Construction	15	2026 (proj.)	PPA	RAC

* Variable pricing based on PJM energy and capacity prices.

Appendix 5J - Potential Unit Retirements for Plan B

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 3	**Yorktown, VA**	**Steam-Cycle**	**Heavy Fuel Oil**	**2023**	**767**	**792**
Chesterfield 5	**Chester, VA**	**Steam-Cycle**	**Coal**	**2023**	**336**	**342**
Chesterfield 6	**Chester, VA**	**Steam-Cycle**	**Coal**	**2023**	**678**	**690**
Chesapeake CT 1	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2025**	**39**	**53**
Chesapeake GT1					15	
Chesapeake GT4					12	
Chesapeake GT6					12	
Lowmoor CT	**Covington, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2025**	**48**	**65**
Lowmoor GT1					12	
Lowmoor GT2					12	
Lowmoor GT3					12	
Lowmoor GT4					12	
Mount Storm CT	**Mt. Storm, WV**	**CombustionTurbine**	**Light Fuel Oil**	**2025**	**11**	**16**
Mt. Storm GT1					11	
Northern Neck CT	**Warsaw, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2025**	**47**	**66**
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**	**2025**	**72**	**93**
Possum Point CT1					12	
Possum Point CT2					12	
Possum Point CT3					12	
Possum Point CT4					12	
Possum Point CT5					12	
Possum Point CT6					12	

(1) Reflects retirement assumptions used for planning purposes, not firm Company commitments except for Chesterfield Units 5 and 6 and Yorktown Unit 3.

Appendix 5K – Planned Changes to Existing Generation Units

Company Name: Virginia Electric and Power Company

Schedule 13

UNIT PERFORMANCE DATA[(1)(2)]

Unit Size (MW) Uprate and Derate

	(ACTUAL)				(PROJECTED)														
Unit Name	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Altavista	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	-	-	18.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 4, 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Anna 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Anna 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Greensville	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	-	-	(1.10)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CVOW (Demonstration)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 5K – Planned Changes to Existing Generation Units

Company Name: Virginia Electric and Power Company

Schedule 13

UNIT PERFORMANCE DATA[(1)(2)]

Unit Size (MW) Uprate and Derate

	(ACTUAL)				(PROJECTED)														
Unit Name	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Remington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City Hybrid Energy Center	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren	-	-	7.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 5L – Environmental Regulations

Constituent		Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
AIR	Hg/HAPS	Mercury & Air Toxics Standards (1) (MATS)	12/16/2011	4/16/2017	Coal & Oil	All affected units compliant
	Hg/HAPs	Mercury & Air Toxics Standards Risk and Technology Review (1)	exp. Q4 2023	exp. Q2 2024	Coal & Oil	The EPA published a proposal in April 2023 to tighten certain aspects of the MATS, rule which include a lower emission limit for filterable particulate matter and required use of CEMS to demonstrate compliance with the fPM limit. Other proposed changes include removal of emission limits for total and individual non-mercury HAPS, and elimination of a "startup" definition. The EPA is expecting to come out with a final action by the end of 2023, with the final strategy and implementation likely occurring in the second quarter of 2024.
	HAPs	NESHAPS for stationary combustion turbines (Subpart YYYY)	2/28/2022	2/2022	New / reconstructed CTs – major HAP loc.	Gas fired combined cycle and simple cycle combustion turbines constructed or reconstructed at major sources of HAP emissions after Jan 14, 2003 must meet the formaldehyde standard.
	SO2	CSAPR (2)	2011	2015/2017	All fossil units > 25 MWs	Allowances (In-Sys.; Trading)
		SO2 NAAQS (75 ppb, 1-hr avg)	6/2/2010	2018	Oil: YT 3	Maintain current % sulfur oil level (3)
	NOx	2015 Ozone Standard (70 ppb)	12/2020		All fossil units > 25 MWs	EPA reconsidering the December 2020 final rule that retained the 2015 NAAQS. EPA aiming to complete reconsideration by end of 2023.
		2015 Ozone NAAQS Interstate Transport Federal Implementation Plan (70 ppb) (21)	12/1/2020	Exp. Q1 2023	All fossil units > 25 MWs	The EPA released a pre-publication of the final federal implementation plan ("FIP") on March 15, 2023, addressing interstate transport for the 2015 Ozone NAAQS. Virginia and West Virginia are covered in the FIP. The EPA revised the CSAPR ozone season NOx emissions trading program with additional restrictions not included in any of the current CSAPR trading programs. Coal-fired electric generating units (excluding circulating fluidized bed ("CFB") boilers) would be subject to daily emission rate limits during ozone season and would have to surrender additional allowances (at a 3:1 ratio) if limits are exceeded after the first 50 tons. *Rule becomes effective within 60 days of publication. Rule expected to be published sometime in May 2023.
		CSAPR Update Rule - Group 3 (17)	4/30/2021	5/1/2021	All fossil units	Allowances (In-Sys.; Trading). Focuses on attainment with 2008 ozone standards. All units in compliance.

Constituent	Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
$PM_{2.5}$	2012 PM 2.5 NAAQs reconsideration	exp. spring 2023		All fossil units	In January, the EPA published a proposed rule resulting from its reconsideration of the primary (health-based) NAAQS for particulate matter ("PM NAAQS"). The EPA is proposing to lower the primary annual $PM_{2.5}$ NAAQS from 12.0 ug/m3 to a level that would fall between 9.0 and 10.0 ug/m3, while soliciting comment on an alternative annual $PM_{2.5}$ standard within the range of 8.0 to 11.0 ug/m3. The EPA is proposing to retain the other PM NAAQs at their current levels, including the secondary 24-hour $PM_{2.5}$ NAAQS. According to the EPA's unified agenda, a final rule is expected in third quarter of 2023
	NSR Permitting for Greenhouse Gases ("GHGs")	5/2010	2011	New/modified fossil units	GHG BACT (On the EPA's unified agenda to revise)
	EGU NSPS (New) (4) (Section 111(b) Subpart TTTT) Proposed revision	Final exp.Q2 2024		New fossil units New units (on/after 12/20/2018)	Build Gas CC or Install CCS 2018 Proposed revision (never finalized): retained the 1,000 lbs/CO_2/MWh limit for new gas CC. Draft expected Q1 2023. The EPA is likely to tighten the limit and require controls on new gas units.
	EGU NSPS (Modified and Reconstructed) (4) Proposed revision (Subpart TTTT) (Section 111(b))	Final exp. Q2 2024		Modified & reconstructed fossil units	Will need to evaluate on a project-by-project basis (draft of rule expected Q1 2023).
	Emission Guidelines for GHG Emissions from Existing EGUs (ACE Replacement rule – Section 111(d))	Final exp. Q2 2024		All existing fossil units	Proposed rule in spring 2023 and final rule expected in spring 2024.

Constituent	Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
CO_2	Virginia CO_2 Budget Trading Rule (RGGI) (12)(5)(16)(20)	Aug-20		Existing and new fossil units ≥ 25 MW; biomass units exempt; biomass emissions from units that co-fire with biomass.	Virginia joined the Regional Greenhouse Gas Initiative ("RGGI") as a direct participant on January 1, 2021 Revenue from the auctions for allowances is returned to the state. Compliance with renewables, new gas, possible unit retirements, and allowance purchases (if applicable). In accordance with the announcement from the acting Secretary of Natural and Historic Resources, Virginia is planning to exit RGGI on December 31, 2023. The period to comment on the repeal rule to exit RGGI ended March 3, 2023.
	Social Cost of Carbon	Jan 2021	Feb 2022	All new/existing coal	Interim social cost of greenhouse gases in effect for federal agencies.
	Efforts to establish GHG NAAQs	Uncertain		All existing/new fossil units	AGs from Oregon, Minnesota, Delaware, Guam, Iowa, Maine, Michigan, and New Mexico signed letter to the EPA supporting GHG NAAQs. While AGs from West Virginia and Kentucky pushed back calling GHG NAAQs "the wrong approach – politically and practically."
	Federal CO_2 Program (Alternative Federal Legislation)	Uncertain	2026	Existing fossil units	Expected price for CO_2.
	The Commonwealth Clean Energy Policy (guidance document only)	7/1/2020	2020 - 2045	Existing and new fossil units	Sets a goal for Virginia to reach net zero emissions by 2045 and additionally states that by 2040 Virginia will have a net zero carbon energy economy. Developing energy resources necessary to produce 30 percent of Virginia's electricity from renewable energy sources by 2030 and 100 percent from Virginia's electricity from carbon-free sources by 2040.
	Virginia Energy Plan (guidance document only)	10/2022	2022 – 2026	Existing and new fossil units, renewables	Encourages investments in hydrogen, carbon capture, and small modular reactors ("SMRs"). The VCEA is to be evaluated based on the latest technology in 2023 and every five years thereafter. Restoring discretion to the SCC concerning plant retirement timelines and authority to defer RPS requirements.
	Federal and state vehicle emission standards	12/1/2021	2023-beyond	Existing and new fossil units	Federal and state rules regulating GHG emissions and low emission vehicle and zero emission vehicle standards. "Electrification" could indirectly impact unit operations

Constituent		Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
		Virginia Clean Economy Act (18)(22)	7/1/2020	2020 - 2045	Existing and new fossil units	The VCEA establishes a mandatory renewable energy portfolio standard in Virginia. There are mandates for significant developments of renewable energy and energy storage resources, as well as retirement of existing carbon-emitting resources. Includes mandatory retirement of certain fossil-generating units (Chesterfield Units 5 & 6 and Yorktown 3 by 2024) and shutting down all remaining fossil generating units by 2045. Allows the utility to petition for relief from these provisions if electric reliability or security is at risk.
		North Carolina – Clean Energy Plan	Uncertain	Uncertain	RM	North Carolina's Clean Energy Plan sets an electric power sector goal of 70% GHG reduction by 2030 (using a 2005 baseline), and a carbon neutrality goal by 2050. The plan fosters long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes and accelerates clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state. *North Carolina still uncertain about joining RGGI (possible earliest date to join is January 2024).
		New Proposed Federal Vehicle Emission Standards	Uncertain	2027	All EGUs (indirectly)	In April 2023, the EPA proposed new vehicle standards for light, medium, and heavy-duty vehicles for model year 2027 and beyond. The EPA's proposal increases the stringency of the standard year-over-year on a phase-in approach. This proposal will affect the Company from an electrification standpoint since it will need to supply the electricity to help the transportation sector decarbonize and deploy charging infrastructure to help energize the transportation sector.
		West Virginia – Senate Bill 793	7/2020	7/2025	MS	Provides relief from B and O taxes if the Company keeps station operational until 2025. Required to pay back if facility is shut down. Can receive benefit beyond 2025, until the Company closes the plant plant or bill is appealed or amended.
WASTE	ASH	CCRs	4/17/2015	2020+	CEC landfill & bottom ash pond	Close landfill, bottom ash pond, & original pond due to station closure. Pond and landfill to be excavated and recycled off site. (7)
				2020+	BR North, East, and West Ash Ponds;	Close all three coal ash ponds by excavating material. East Pond and West Pond material has been excavated and consolidated in North Pond. Plan is to construct new landfill on property adjacent to North Pond, close North Pond by removal of CCR material, and place CCR material into new landfill, and close new landfill. (6)
				2020+	PP A/B/C, D and E Ponds	All five ponds to be closed. Ponds A/B/C and E have been excavated of CCR and material consolidated in Pond D. Plan is to construct new landfill adjacent to Pond D. Continuing to evaluate onsite and offsite disposal options or offsite recycling. (6)

Constituent		Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
				2020+	CH 3, 4, 5 & 6, Lower and Upper Ponds	Lower and Upper Ponds Closure through excavation of CCR material and hauling to onsite or offsite landfill for disposal or offsite for recycling. (6)
				2020	YT 1, 2	Landfill closure (due to coal unit retirements). Closure completed September 20, 2020.
				10/2018	CL 2 FGD Ponds;	Ponds retrofitted in compliance with CCR Rule and placed back into service.
				10/2018	MS Finger and Pyrite Ponds	Pond closure, retrofit, and/or rebuilding. Three of the five original ponds placed back into service in compliance with CCR Rule.
				TBD	BR, CEC, CH, CL, MS, PP, VCHEC, YT	Monitor groundwater and corrective actions, if needed.
WATER	Water 316b	316(b) Impingement & Entrainment (7)(8) Thermal discharge biological effects	5/19/2014	2016 (14)	BG	Rule 316(b) studies to determine compliance needs and submit design & source water body data
				2019 (9)(14)	NA, AV	Rule 316(b) studies to determine compliance needs and submit design & source water body data VSDs; Screens; Fish Returns
				2020 (14)	SU, PP	
				2021	CH	
				2022 (10)	YT3	
				2022	CL	
				(10)		
				2028(11)(14)	NA	VSDs; Screens; Fish Returns
				2028 (11)(14)	SU	
				2023,2028 (11)(14)	CH 5,6,7,8 (19)	
				NA	CH, SU	Surry's Rule 316(a) demonstration update report submitted on August 25, 2020. Chesterfield's Rule 316(a) demonstration update report submitted on December 29, 2020 Fish protection pilot study conducted in 2021 may help mitigate future required measures at Chesterfield. Decision to reissue Rule 316(a) variance at both Chesterfield and Surry will be made by the Virginia Department of Environmental Quality ("VDEQ") during next permit reissuance process expected – 2024-2025.

Constituent		Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
	316(a)	Thermal discharge biological effects Effluent Limitation Guidelines (12)	9/30/2015	NA	MS	Rule 316(a) variance pursued since 2007 under an Administrative Order. Litigation initiated in 2021 by Sierra Club and Potomac Riverkeeper. Last administrative order has a requirement to meet either the 5-degree delta or the requirements for the Rule 316(a) variance by October 31, 2022, which was achieved, and the Administrative Order is closed. Air-cooled chillers have been rented and installed to meet the 5-degree delta requirement for the first two years. The Company is investigating the installation of permanent chillers at the site two years out.
				12/2023	CH 5,6	No longer a concern because of compliance with the FGD ELG limits due to retirement in 2023.
	Water ELG	Effluent Limitation Guidelines (12)	9/30/2015	3/31/2024 (13)	MS	Bottom Ash - Closed loop wet system
WILDLIFE	Threatened & Endangered	Atlantic Sturgeon Endangered Species Listing	2/6/2012	2027 (15)	CH	Incidental take permit ("ITP") issued December 2020 with 5-year permit term. ITP permit modification is in process to reflect new findings. Final modification timeline is unknown. A successful modification of the ITP will reduce the Company's operational constraints associated with risk of take. Retirement of Units 5 and 6 will reduce the Company's estimated incidental take to some extent, but Unit 6 will still need coverage for ongoing water withdrawals. BTA for protection of Atlantic Sturgeon to be determined by VDEQ as part of Rules 316(b) and 316(a) processes during next permit reissuance expected 2022-2023.
		Atlantic Sturgeon Critical Habitat Designation	2017	2027 (15)	CH	Thermal discharge Rule 316(a) studies completed during 2020 at Chesterfield and Surry to determine compliance needs during NPDES permit reissuance. Results of studies will be considered in BTA determinations by VDEQ under Rules 316(b) and 316(a) duringthe next permit reissuance process.
		Atlantic Sturgeon Critical Habitat Designation	2017		ATS CHD may be a consideration for PP, SU and CH permits.	

<u>**Notes: Compliance assumed January 1 unless otherwise noted.**</u>

1) EPA is looking at reconsidering MATS RTR.

2) SO_2 allowances decreased by 50% in 2017. Retired units retain CSAPR allowances for 4 years. System is expected to have sufficient SO_2 allowances.

3) SO_2 NAAQS modeling submitted to VDEQ in November 2016. Modeling shows compliance with the NAAQS. The EPA has approved and issued notice indicating NAAQS attainment August 2017. In March 2019, the EPA published the final rule retaining 75 ppb 1-hr SO_2 NAAQS. No additional impacts expected.

4) The 2015 rule is under EPA review for possible repeal or replacement rule. The EPA published proposed revisions on December 20, 2018.

5) In August 2020, VDEQ issued a final rule establishing a cap-and-trade program for direct participation in RGGI starting on January 1, 2021, and includes about a 30% reduction in the regional cap from 2021 levels by 2030.

6) As a result of the SB 1355 legislation (Virginia Code § 10.1-1402.03), ash in ponds must be excavated and disposed of in the landfill or taken off site for recycling. Exact timing of the start of work at each site is to be determined.

7) Agency determined the 316(b) 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."

8) All known Rule 316(b) studies have been submitted. Technology determinations pending from VDEQ in next permit renewals.

9) Rule 316(b) information for NA submitted and under consideration by VDEQ.

10) Y3 required to retire by December 21, 2024, by the VCEA. The information required by the rule was submitted to VDEQ on July 21, 2022.

11) Assumes permit issued with a 4-year compliance schedule. Projected permit issuance dates: NA - January 2024, SU - March 2024, CH - September 2024.

12) The rule does not apply to EGUs < 25 MW, , biomass units, or biomass emissions from units that co-fire with biomass (*i.e.,* VCHEC).

13) March 31, 2024 is the applicability deadline that was submitted to DEP for their approval in October 2021.

14) Rule 316(b) studies and reports completed and submitted to agency. Permits administratively continued and waiting for BTA determination.

15) Compliance dates are determined during NPDES permit reissuance process and are expected to be the same as those shown for Rule 316(b) compliance.

16) Cost of allowances can be recovered by Phase I and Phase II utilities from ratepayers.

17) Final rule required the EPA to issue FIPs with revised tighter NOx allowance budgets via a Group 3 Trading program.

18) The VCEA includes a provision to adopt regulations no earlier than July 1, 2024, to reduce CO_2 using a multistate trading program for the period of 2031 to 2050.

19) Having the units shutdown prior to the ELG-driven deadline of December 31,2023 relieves DE of any further Rule 316(b) compliance requirements for Units 5 & 6. Compliance is satisfied by shutting the units down because they are no longer withdrawing cooling water, and therefore Rule 316(b) requirements will not apply.

20) On January 15, 2022, Governor Youngkin signed Executive Order 9, which orders the VDEQ to start the process to withdraw Virginia from RGGI.

21) The EPA issued prepublication of Federal Implementation Plans in March 2023.

22) The VCEA became the roadmap for Executive Order 43. The Virginia Department of Mines, Minerals, and Energy, now known as the Virginia Department of Energy, modeling submitted on January 1, 2022, is the plan of action.

Appendix 5M - Tabular Results of Busbar

	Capacity Factor (%)										
$/kW-Year	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
3x1 CC Greenfield	$ 250	$ 282	$ 314	$ 346	$ 378	$ 410	$ 442	$ 474	$ 506	$ 538	$ 570
2x1 CC Greenfield	$ 281	$ 312	$ 343	$ 374	$ 405	$ 436	$ 468	$ 499	$ 530	$ 561	$ 592
1x1 CC Greenfield	$ 330	$ 369	$ 407	$ 446	$ 485	$ 524	$ 562	$ 601	$ 640	$ 678	$ 717
CT	$ 134	$ 195	$ 256	$ 316	$ 377	$ 438	$ 498	$ 559	$ 620	$ 681	$ 741
CT (Aero)	$ 253	$ 301	$ 348	$ 395	$ 443	$ 490	$ 538	$ 585	$ 633	$ 680	$ 727
Nuclear SMR	$ 1,264	$ 1,259	$ 1,255	$ 1,250	$ 1,245	$ 1,241	$ 1,236	$ 1,232	$ 1,227	$ 1,222	$ 1,218
Solar				$ 124							
Distributed Solar (3 MW)				$ 415							
Wind - On-Shore					$ 219						
Wind - Off-Shore					$ 287						
Battery Generic 4H (30 MW)			$ 384								
Pump Hydro Storage (300 MW)			$ 1,076								

Notes:

(1) Offshore Wind has a capacity factor of 43%.

(2) Onshore Wind has a capacity factor of 37%.

(3) Solar has a capacity factor of 25%.

(4) Distributed solar has a capacity factor of 24%.

(5) Batteries and Pump Storage have a capacity factor of 15%.

Appendix 5N - Busbar Assumptions

Nominal $	Heat Rate	Variable Cost (1)	Fixed Cost (2)		Book Life	2023 Real $ (3)
	MMBtu/MWh	$/MWh	$/kW-Year	$/MWh	Years	$/kW
3x1 CC Greenfield	5.39	$37	$250	$36	36	$977
2x1 CC Greenfield	5.40	$35	$281	$40	36	$1,215
1x1 CC Greenfield	5.42	$44	$330	$47	36	$1,574
CT	8.88	$69	$134	$102	36	$1,179
CT (Aero)	8.03	$54	$253	$193	36	$2,312
Nuclear SMR	12.17	-$5	$1,264	$157	60	$10,954
Solar - Tracker	-	-$32	$209	$96	35	$2,006
Distributed Solar (3 MW)	-	-$9	$440	$213	35	$4,522
Wind - On-Shore	-	-$32	$331	$101	25	$2,356
Wind - Off-Shore	-	-$33	$403	$106.26	30	$3,965
Battery Generic 4H (30 MW)	-	$50	$296	$225	20	$2,863
Pump Hydro Storage (300 MW)	-	$74	$946	$720	50	$9,667

Notes:

(1) Variable costs for solar and wind includes RECs value.

(2) Fixed costs include capital expenditures, fixed O&M, federal tax credits, and gas firm transmission expenses.

(3) Values in this column represent overnight installed cost.

Appendix 5O – Renewable Resources (for Plan B)

Company Name: Virginia Electric and Power Company

Schedule 11

RENEWABLE RESOURCE GENERATION (GWh)

Resource Type[(1)]	Unit Name	State	C.O.D.[(2)]	Build / Purchase / Convert[(3)]	Life/ Duration[(4)]	Size MW[(5)]	2020 (ACTUAL)	2021 (ACTUAL)	2022 (ACTUAL)	2023 (PROJECTED)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Hydro																									
	Gaston Hydro	NC	1963	Build	N/A	220	376	276	219	330	331	330	330	330	331	330	330	330	331	330	330	330	331	330	330
	North Anna Hydro	VA	1987	Build	N/A	1	1	0	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Roanoke Rapids Hydro	NC	1955	Build	N/A	95	401	386	145	295	296	295	295	295	296	295	295	295	296	295	295	295	296	295	295
Sub-total: NC						315	778	661	363	625	627	625	625	625	627	625	625	625	627	625	625	625	627	625	625
Sub-total: VA						1	1	0	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Sub-total: Hydro						316	778	661	363	627	629	627	627	627	629	627	627	627	629	627	627	627	629	627	627
Solar																									
	Existing VA Solar PPAS 202(	VA	2020	Purchase	20	67	-	-	-	150	150	150	151	150	150	150	151	150	150	150	151	150	150	150	151
	Grassfield Solar	VA	2023	Build	35	20	-	-	-	39	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36
	Norge Solar	VA	2023	Build	35	20	-	-	-	39	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36
	Cavalier PPA	VA	2025	Purchase	20	155	-	-	-	-	-	302	300	299	298	295	294	292	292	289	288	286	286	283	282
	Chesapeake PPA	VA	2024	Purchase	20	118	-	-	-	-	230	228	227	225	225	223	222	221	221	219	217	216	216	214	213
	Pleasant Hill PPA	VA	2023	Purchase	20	20	-	-	-	39	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36
	Rivanna PPA	VA	2024	Purchase	20	13	-	-	-	-	24	24	24	23	23	23	23	23	23	23	23	23	22	22	22
	Watlington PPA	VA	2023	Purchase	20	20	-	-	-	39	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36
	Wythe 2 PPA	VA	2024	Purchase	20	75	-	-	-	-	146	145	144	143	143	142	141	140	140	139	138	137	137	136	135
	Sycamore Solar	VA	2023	Build	35	42	-	-	-	81	81	81	80	80	80	79	79	78	78	77	77	77	76	76	75
	Black Bear Distributed	VA	2024	Build	35	2	-	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Clean Energy 2 DER 2	VA	2023	Purchase	20	15	-	-	-	29	29	29	29	29	28	28	28	28	28	28	27	27	27	27	27
	Clean Energy 2 DER 3	VA	2023	Purchase	20	7	-	-	-	14	14	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	Springfield Distributed	VA	2024	Build	35	2	-	-	-	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	360 PPA	VA	2027	Purchase	20	52	-	-	-	-	-	-	-	101	101	100	99	99	99	98	97	97	97	96	95
	Cox PPA	VA	2024	Purchase	20	16	-	-	-	-	31	31	31	31	31	30	30	30	30	30	29	29	29	29	29
	Ho Fel PPA	VA	2025	Purchase	20	40	-	-	-	-	-	78	77	77	77	76	76	75	75	74	74	74	74	73	73
	Sinai PPA	VA	2024	Purchase	20	10	-	-	-	-	19	19	19	19	19	19	19	19	18	18	18	18	18	18	18
	Stratford PPA	VA	2023	Purchase	20	15	-	-	-	29	29	29	29	29	28	28	28	28	28	28	27	27	27	27	27
	Surry PPA	VA	2025	Purchase	20	20	-	-	-	-	-	39	39	38	38	38	38	38	38	37	37	37	37	36	36
	Camellia Solar	VA	2024	Build	35	20	-	-	-	-	35	35	35	35	35	34	34	34	34	34	33	33	33	33	33
	Dulles Tied Solar	VA	2026	Build	35	100	-	-	-	-	-	-	173	172	171	170	169	168	168	166	166	165	164	163	162
	Fountain Creek Solar	VA	2024	Build	35	80	-	-	-	-	155	154	153	152	152	150	150	149	149	147	147	146	146	144	143
	Otter Creek Solar	VA	2024	Build	35	60	-	-	-	-	117	116	115	115	114	113	113	112	112	111	111	110	110	109	108
	Piney Creek Base Solar	VA	2024	Build	35	80	-	-	-	-	156	154	154	153	153	151	151	150	150	148	147	147	146	145	144
	Quillwort Solar	VA	2024	Build	35	18	-	-	-	-	35	35	35	34	34	34	34	34	34	33	33	33	33	33	32
	Sebera Solar	VA	2024	Build	35	18	-	-	-	-	31	31	31	31	31	30	30	30	30	30	30	30	29	29	29
	Solidago Solar	VA	2023	Build	35	20	-	-	-	39	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36
	Sweet Sue Solar	VA	2026	Build	35	75	-	-	-	-	-	-	145	144	144	143	142	141	141	140	139	138	138	137	136
	Walnut Solar	VA	2023	Build	35	150	-	-	-	262	261	259	258	256	256	254	253	251	250	249	247	246	245	243	242
	Winterberry Solar	VA	2023	Build	35	20	-	-	-	39	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36
	Winterpock Solar	VA	2024	Build	35	20	-	-	-	-	39	39	38	38	38	38	38	37	37	37	37	37	37	36	36
	Augusta PPA	VA	2025	Purchase	20	105	-	-	-	-	-	204	203	202	201	200	199	198	197	196	195	193	193	191	190
	Clean Energy 3 DER 1	VA	2024	Purchase	20	3	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Clean Energy 3 DER 2	VA	2024	Purchase	20	12	-	-	-	-	24	23	23	23	23	23	23	23	23	23	22	22	22	22	22
	Pivot Energy VA 2	VA	2025	Purchase	20	1	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Groves PPA	VA	2027	Purchase	20	16	-	-	-	-	-	-	-	29	29	28	28	28	28	28	28	27	27	27	27
	Harrisonburg PPA	VA	2027	Purchase	20	15	-	-	-	-	-	-	-	29	29	29	29	29	28	28	28	28	28	28	27
	Jarratt PPA	VA	2025	Purchase	20	48	-	-	-	-	-	94	93	93	93	92	92	91	91	90	90	89	89	88	88
	Switchgrass PPA	VA	2025	Purchase	20	69	-	-	-	-	-	126	125	124	124	123	122	122	122	121	120	119	119	118	117
	Bridleton Solar	VA	2026	Build	35	20	-	-	-	-	-	-	35	35	35	35	35	34	34	34	34	34	34	33	33
	Cerulean Solar	VA	2026	Build	35	62	-	-	-	-	-	-	120	120	119	118	118	117	117	116	115	115	114	114	113
	Courthouse Solar	VA	2026	Build	35	167	-	-	-	-	-	-	299	298	297	295	293	292	291	289	287	286	285	283	281
	Ivy Landfill Distributed	VA	2025	Build	35	3	-	-	-	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Racefield Distributed	VA	2025	Build	35	3	-	-	-	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Kings Creek Solar	VA	2026	Build	35	20	-	-	-	-	-	-	36	36	36	35	35	35	35	35	35	34	34	34	34
	Southern VA Solar	VA	2025	Build	35	125	-	-	-	-	-	218	217	216	215	214	213	212	211	210	209	207	207	205	204
	Moon Corner Solar	VA	2026	Build	35	60	-	-	-	-	-	-	116	116	115	115	114	113	113	112	112	111	111	110	109
	North Ridge Solar	VA	2026	Build	35	20	-	-	-	-	-	-	39	39	39	38	38	38	38	38	37	37	37	37	37
	Solar_DG Hybrid - (3MW)	VA	2030	Build/Purchase	35	0	-	-	-	-	-	-	-	-	-	-	87	302	517	729	940	1,157	1,376	1,586	1,799
	Solar_DG Hybrid - (3MW) 2(	VA	2027	Build/Purchase	35	3	-	-	-	-	-	-	-	29	29	29	29	29	28	28	28	28	28	28	27
	Solar_DG Hybrid - (3MW) 2(	VA	2028	Build/Purchase	35	3	-	-	-	-	-	-	-	-	58	58	58	57	57	57	56	56	56	56	55
	Solar_DG Hybrid - (3MW) 2(	VA	2029	Build/Purchase	35	3	-	-	-	-	-	-	-	-	-	87	87	86	86	86	85	85	84	84	83
	Generic Solar PV Hybrid- (6(	VA	2030	Build/Purchase	35	60	-	-	-	-	-	-	-	-	-	-	1,398	3,137	4,883	6,591	8,304	10,009	11,739	13,393	15,071
	Generic Solar PV Hybrid- (6(	VA	2027	Build/Purchase	35	60	-	-	-	-	-	-	-	1,165	1,162	1,153	1,147	1,141	1,139	1,130	1,124	1,118	1,115	1,106	1,100
	Generic Solar PV Hybrid- (6(	VA	2028	Build/Purchase	35	60	-	-	-	-	-	-	-	-	1,285	1,275	1,268	1,262	1,259	1,249	1,243	1,236	1,233	1,223	1,217
	Generic Solar PV Hybrid- (6(	VA	2029	Build/Purchase	35	60	-	-	-	-	-	-	-	-	-	1,281	1,275	1,268	1,265	1,255	1,249	1,243	1,240	1,230	1,223
	Water Strider PPA	VA	2016	Purchase	17	80	-	118	178	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
	Westmoreland PPA	VA	2016	Purchase	17	20	-	11	48	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
	Solar Partnership Program	VA	2016	Build	12	7	6	9	5	9	9	9	9	9	9	9	9	9	9	9	8	8	-	-	-
	Scott Solar	VA	2016	Build	34	17	32	30	31	33	33	33	33	33	33	32	32	32	32	32	32	31	31	31	31
	Whitehouse Solar	VA	2016	Build	34	20	34	38	31	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36	36
	Woodland Solar	VA	2016	Build	34	19	32	37	28	37	37	37	36	36	36	36	36	35	35	35	35	35	35	34	34
	Colonial Trail West	VA	2019	Build	35	142	301	276	275	273	272	270	269	267	267	265	264	262	261	259	258	257	256	254	253
	Spring Grove	VA	2020	Build	35	98	7	203	178	189	188	187	186	185	184	183	182	181	181	179	179	177	177	176	175
	Sadler Solar	VA	2021	Build	34	100	-	161	187	194	195	194	194	194	195	194	194	194	195	194	194	194	195	194	194
Sub-total: NC						0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total: VA						2,892	412	-	-	1,766	2,817	3,872	4,819	6,149	7,479	8,794	10,237	12,149	14,091	15,946	17,830	19,709	21,630	23,430	25,280
Sub-total: Solar						2,892	412	-	-	1,766	2,817	3,872	4,819	6,149	7,479	8,794	10,237	12,149	14,091	15,946	17,830	19,709	21,630	23,430	25,280

Company Name: Virginia Electric and Power Company

RENEWABLE RESOURCE GENERATION (GWh)

Appendix 5O – Renewable Resources (for Plan B)

Schedule 11

Resource Type[1]	Unit Name	State	C.O.D.[2]	Build / Purchase / Convert[3]	Life/ Duration[4]	Size MW[5]	2020 (ACTUAL)	2021 (ACTUAL)	2022 (ACTUAL)	2023	2024 (PROJECTED)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Wind																									
Offshore	CVOW (Demonstration)	VA	2021	Build	27	12	13	50	51	40	41	40	40	40	41	40	40	40	41	40	40	40	41	40	40
Offshore	CVOW - Phase 1 (2587MW)	VA	2027	Build	30	2,587	-	-	-	-	-	-	-	9,523	9,567	9,523	9,523	9,523	9,567	9,523	9,523	9,523	9,567	9,523	9,523
Offshore	CVOW - Phase 2 (2587MW)	VA	2033	Build	30	2,600	-	-	-	-	-	-	-	-	-	-	-	-	-	9,571	9,571	9,571	9,615	9,571	9,571
Onshore	New Wind_80MW	VA	2028	Build	25	80	-	-	-	-	-	-	-	-	283	282	282	282	283	282	282	282	283	282	282
Onshore	New Wind_120MW	VA	2028	Build	25	120	-	-	-	-	-	-	-	-	366	364	364	364	366	364	364	364	366	364	364
Onshore	Generic Wind- (60MW)	VA	2028	Build	25	60	-	-	-	-	-	-	-	-	198	197	197	394	396	394	592	592	594	789	789
Sub-total: NC						0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total: VA						5,459	13	50	51	40	41	40	40	9,563	10,454	10,407	10,407	10,604	10,652	20,175	20,372	20,372	20,465	20,569	20,569
Sub-total: Wind						5,459	-	50	51	40	41	40	40	9,563	10,454	10,407	10,407	10,604	10,652	20,175	20,372	20,372	20,465	20,569	20,569
Total Renewables: NC						315	778	661	363	625	627	625	625	625	627	625	625	625	627	625	625	625	627	625	625
Total Renewables: VA						8,352	426	50	51	1,809	2,860	3,915	4,862	15,715	17,936	19,203	20,646	22,756	24,745	36,123	38,204	40,083	42,097	44,001	45,852
Total Renewables						8,667	1,191	711	414	2,434	3,487	4,540	5,487	16,340	18,563	19,828	21,271	23,381	25,372	36,748	38,829	40,708	42,724	44,626	46,477

(1) Per definition in Va. Code § 56-576.
(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 hydro, nameplate for solar and wind.

Appendix 5P – Potential Supply- Side Resources for Plan B

Company Name: ______________________________ **Schedule 15b**

UNIT PERFORMANCE DATA

Potential Supply-Side Resources (MW)

Unit Name	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Annual Firm	MW Nameplate
Solar 2027	Intermittent	Solar	2027	163	615
Solar 2028	Intermittent	Solar	2028	183	690
Generic CT	Peak	Natural Gas	2028	970	970
Onshore Wind	Intermittent	Wind	2028	31	260
Generic Battery	Storage		2028	79	90
Solar 2029	Intermittent	Solar	2029	187	705
Generic Battery	Storage		2029	105	120
Solar 2030	Intermittent	Solar	2030	203	765
Generic Battery	Storage		2030	131	150
Solar 2031	Intermittent	Solar	2031	268	1,011
Onshore Wind	Intermittent	Wind	2031	7	60
Generic Battery	Storage		2031	158	180
Solar 2032	Intermittent	Solar	2032	268	1,011
Generic Battery	Storage		2032	158	180
Solar 2033	Intermittent	Solar	2033	268	1,011
Offshore Wind	Intermittent	Wind	2033	797	2,600
Generic Battery	Storage		2033	210	240
Solar 2034	Intermittent	Solar	2034	268	1,011
Onshore Wind	Intermittent	Wind	2034	7	60
Generic Battery	Storage		2034	210	240
Nuclear	Baseload	Uranium	2034	268	268
Solar 2035	Intermittent	Solar	2035	269	1,014
Generic Battery	Storage		2035	236	270
Generic CT	Peak	Natural Gas	2035	485	485
Solar 2036	Intermittent	Solar	2036	269	1,014
Generic Battery	Storage		2036	263	300
Nuclear	Baseload	Uranium	2036	268	268
Generic CT	Peak	Natural Gas	2036	485	485
Solar 2037	Intermittent	Solar	2037	269	1,014
Onshore Wind	Intermittent	Wind	2037	7	60
Generic Battery	Storage		2037	263	300
Generic CT	Peak	Natural Gas	2037	485	485
Solar 2038	Intermittent	Solar	2038	269	1,014
Generic Battery	Storage		2038	263	300
Nuclear	Baseload	Uranium	2038	268	268
Generic CT	Peak	Natural Gas	2038	485	485

(1) Estimated commercial operation date

Company Name:
UTILITY CAPACITY POSITION (MW)

Appendix 5Q – Summer Capacity Position for Plan B

Virginia Electric and Power Company

Schedule 16

	(ACTUAL)			(PROJECTED)															
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Existing Capacity																			
Conventional	17,228	17,200	17,195	15,116	15,116	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872
Renewable NC	-	-	-	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
Renewable VA	72	128	224	791	1,279	1,295	1,212	1,130	961	861	802	711	633	615	597	580	570	562	553
Renewable	72	128	224	1,106	1,594	1,610	1,527	1,445	1,276	1,176	1,117	1,026	948	930	912	895	885	877	868
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	1,840	1,851	1,850	1,850	1,851	1,851	1,852	1,851	1,851	1,851	1,850	1,849	1,849	1,848	1,847	1,847
Storage	1,809	1,809	1,809	1,840	1,851	1,850	1,850	1,851	1,851	1,852	1,851	1,851	1,851	1,850	1,849	1,849	1,848	1,847	1,847
Total Existing Capacity	19,109	19,137	19,228	18,062	18,561	18,332	18,249	18,168	17,999	17,899	17,840	17,748	17,670	17,652	17,633	17,615	17,604	17,595	17,586
Generation Under Construction																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	-	290	546	1,505	1,395	1,267	1,238	1,140	1,179	1,015	1,006	997	993	989	985
Renewable	-	-	-	-	-	290	546	1,505	1,395	1,267	1,238	1,140	1,179	1,015	1,006	997	993	989	985
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	53	154	161	166	170	172	170	168	164	160	156	152	149	145
Storage	-	-	-	-	-	53	154	161	166	170	172	170	168	164	160	156	152	149	145
Total Planned Construction Capacity	-	-	-	-	-	344	700	1,667	1,561	1,437	1,410	1,310	1,346	1,179	1,166	1,154	1,146	1,138	1,130
Generation Under Development																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage NC	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Development Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Potential (Expected) New Capacity																			
Conventional	-	-	-	-	-	-	-	-	970	970	970	970	970	970	1,214	1,699	2,428	2,913	3,642
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-		-	-	-	-	-	295	546	730	919	1,079	1,166	2,083	2,260	2,415	2,592	2,768	2,930
Renewable	-	-	-	-	-	-	-	295	546	730	919	1,079	1,166	2,083	2,260	2,415	2,592	2,768	2,930
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	83	202	356	540	720	944	1,160	1,397	1,646	1,884	2,109
Storage	-	-	-	-	-	-	-	-	83	202	356	540	720	944	1,160	1,397	1,646	1,884	2,109
Total Potential New Capacity	-	-	-	-	-	-	-	295	1,599	1,901	2,245	2,589	2,856	3,997	4,634	5,510	6,666	7,565	8,681
Other (PPA)																			
Conventional	-	-	-	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	64	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
Renewable	-	-	64	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
Storage NC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other (PPA) Capacity	-	-	64	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224
Unforced Availability	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Generation Capacity	19,109	19,137	19,293	18,286	18,784	18,899	19,172	20,354	21,383	21,460	21,718	21,871	22,096	23,050	23,657	24,502	25,640	26,522	27,621
Energy Efficiency & Demand Response(1)	74	331	186	198	396	604	655	701	722	734	735	742	758	783	785	790	778	790	822
Customer Choice(1)	-	-	-	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668
Net Generation & Demand-side	19,183	19,467	19,479	18,286	18,784	18,899	19,172	20,354	21,383	21,460	21,718	21,871	22,096	23,050	23,657	24,502	25,640	26,522	27,621
Capacity Sale(3)	-	-	961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Purchase(3)	858	468	-	1,245	1,019	999	1,496	684	83	486	788	1,217	1,707	1,513	1,847	1,998	1,956	2,211	2,423
Capacity Adjustment(3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Requirement or PJM Capacity Obligation	20,041	19,935	18,518	19,531	19,804	19,898	20,668	21,038	21,466	21,946	22,507	23,088	23,803	24,563	25,504	26,501	27,596	28,732	30,044
Net Utility Capacity Position	-	-	-	(1,245)	(1,019)	(999)	(1,496)	(684)	(83)	(486)	(788)	(1,217)	(1,707)	(1,513)	(1,847)	(1,998)	(1,956)	(2,211)	(2,423)

(1) Values accounted for 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) 2020 and 2021 actual historical data based upon measured and verified EM&V results; 2022 historical data based on projections

Appendix 5R – Capacity Position for Plan B

Company Name: Virginia Electric and Power Company **Schedule 4**

POWER SUPPLY DATA

	(ACTUAL)			(PROJECTED)															
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
I. Capability (MW)																			
1. Summer																			
a. Firm Capacity Capacity(1)	19,109	19,137	19,228	18,062	18,561	18,676	18,948	20,130	21,159	21,237	21,495	21,647	21,873	22,827	23,434	24,279	25,416	26,298	27,397
b. Positive Interchange Commitments(2)	-	-	64	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224
c. Capacity Sale(3)	-	-	961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Capacity Purchase(3)	858	468	-	1,245	1,019	999	1,496	684	83	486	788	1,217	1,707	1,513	1,847	1,998	1,956	2,211	2,423
e. Capacity Adjustment(3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
f. Total Net Summer Capability(4)	19,966	19,605	20,254	19,531	19,804	19,898	20,668	21,038	21,466	21,946	22,507	23,088	23,803	24,563	25,504	26,501	27,596	28,732	30,044
2. Winter																			
a. Firm Capacity Capacity(1)	19,109	19,137	19,228	18,530	18,549	18,272	18,378	20,328	21,499	21,631	21,800	22,001	22,183	24,357	24,855	25,621	26,669	27,443	28,466
b. Positive Interchange Commitments(2)	-	-	64	157	157	157	157	157	157	157	157	157	157	157	157	157	157	157	157
e. Total Net Winter Capability(4)	19,109	19,137	19,293	18,687	18,706	18,429	18,535	20,485	21,656	21,788	21,957	22,158	22,340	24,514	25,012	25,778	26,826	27,600	28,623

(1) Net seasonal capability.

(2) Does not include firm commitments from existing purchase power agreements and estimated solar PPAs.

(3) Capacity sale, purchase, and adjustments are used for modeling purposes.

(4) Does not include behind-the-meter generation MW.

*Demand response programs are not classified as capacity resources and are included in adjusted load (Appendix 4H)

Appendix 5S – Construction Forecast

Company Name: Virginia Electric and Power Company

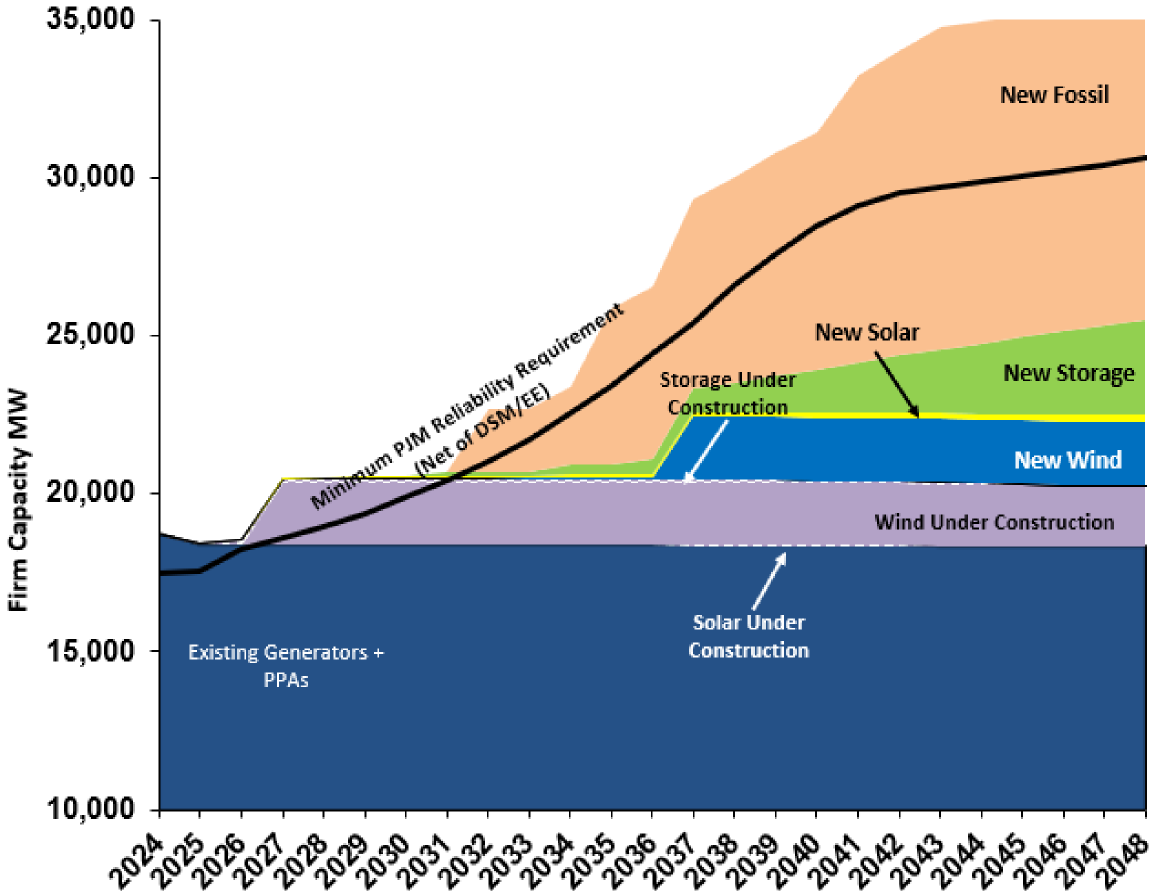
Schedule 17

CONSTRUCTION COST FORECAST (Thousand Dollars)

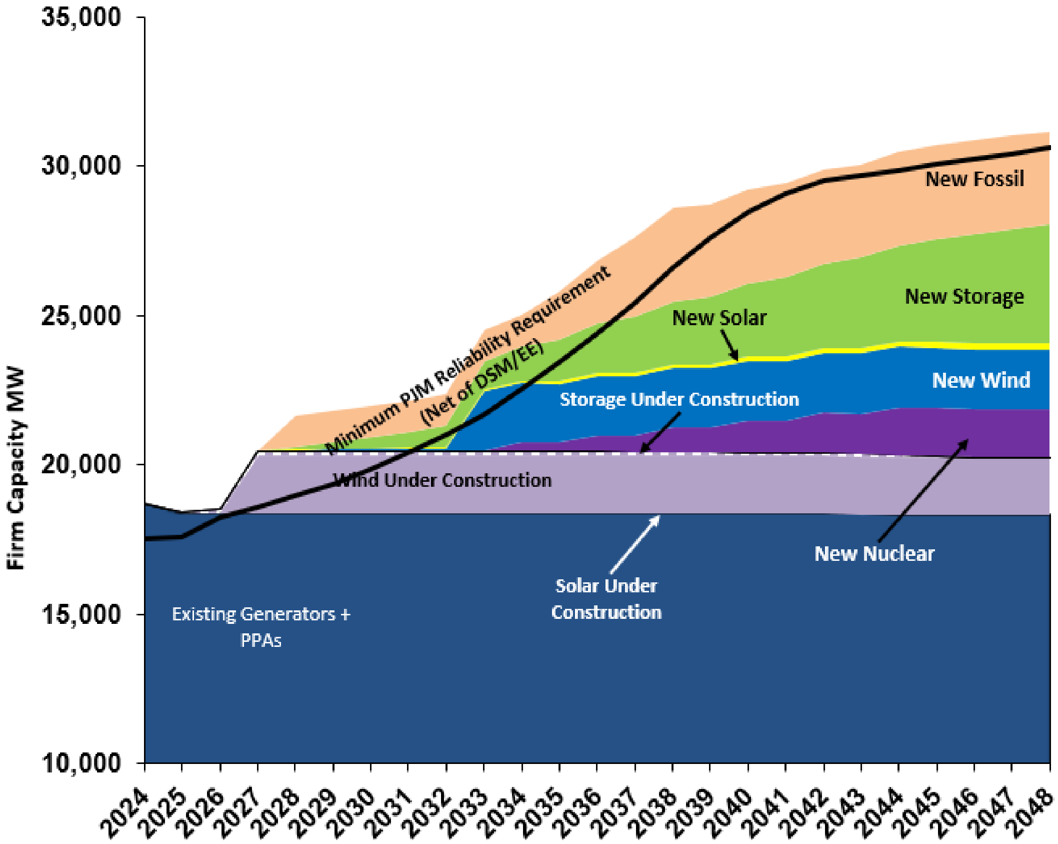
(PROJECTED)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
I. New Traditional Generating Facilities																
a. Construction Expenditures (non-AFUDC)	-	17,083	175,995	370,545	730,162	812,976	806,240	1,345,699	1,658,966	2,180,637	2,335,587	2,442,488	2,330,238	2,190,722	2,003,177	1,863,440
b. AFUDC	-	29	357	1,286	3,158	5,781	5,016	8,675	13,783	20,311	27,989	36,112	32,819	38,171	31,054	35,199
c. Annual Total	-	17,112	176,353	371,831	733,320	818,757	811,256	1,354,374	1,672,749	2,200,948	2,363,575	2,478,600	2,363,057	2,228,893	2,034,231	1,898,639
d. Cumulative Total	-	17,112	193,464	565,296	1,298,615	2,117,372	2,928,628	4,283,002	5,955,751	8,156,699	10,520,275	12,998,875	15,361,932	17,590,825	19,625,056	21,523,695
II. New Renewable Generating Facilities																
a. Construction Expenditures (non-AFUDC)	108,935	800,624	611,325	1,154,869	1,455,289	2,360,001	3,892,505	4,620,973	4,175,148	2,509,425	1,747,936	1,595,035	1,580,487	1,617,133	1,588,485	1,337,752
b. AFUDC	185	1,732	4,132	7,135	11,572	15,083	20,191	31,338	42,834	48,778	51,090	11,909	11,680	11,988	12,251	11,358
c. Annual Total	109,120	802,356	615,457	1,162,004	1,466,861	2,375,084	3,912,697	4,652,312	4,217,982	2,558,203	1,799,027	1,606,944	1,592,167	1,629,121	1,600,736	1,349,110
d. Cumulative Total	109,120	911,476	1,526,933	2,688,937	4,155,798	6,530,882	10,443,579	15,095,890	19,313,872	21,872,075	23,671,102	25,278,045	26,870,212	28,499,333	30,100,069	31,449,179
III. New Storage Facilities																
a. Construction Expenditures (non-AFUDC)	-	-	20,462	43,171	111,595	210,681	255,055	309,069	344,936	392,225	453,425	481,520	527,624	526,712	536,242	483,772
b. AFUDC	-	-	35	143	406	954	1,189	1,419	1,637	1,808	2,155	2,279	2,517	2,636	2,568	2,415
c. Annual Total	-	-	20,497	43,314	112,001	211,635	256,245	310,488	346,574	394,033	455,580	483,799	530,142	529,347	538,810	486,187
d. Cumulative Total	-	-	20,497	63,811	175,812	387,447	643,691	954,180	1,300,753	1,694,787	2,150,367	2,634,165	3,164,307	3,693,654	4,232,464	4,718,651
IV. Other Facilities																
a. Transmission	1,581,714	1,560,480	1,824,764	1,795,733	1,823,052	1,863,346	1,879,406	1,882,439	1,430,000	1,430,000	1,430,000	1,430,000	1,430,000	1,430,000	1,430,000	1,430,000
b. Distribution	1,386,177	1,399,451	1,408,764	1,439,768	1,417,925	1,370,855	1,247,114	1,052,248	1,105,986	1,156,618	1,255,413	1,291,319	1,325,852	985,656	1,005,572	1,025,371
c. Energy Conservation & DR																
d. Other																
e. AFUDC	75,372	103,003	136,962	169,867	142,448	101,154	84,094	81,061	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
f. Annual Total	3,043,263	3,062,935	3,370,490	3,405,368	3,383,425	3,335,355	3,210,614	3,015,748	2,605,986	2,656,618	2,755,413	2,791,319	2,825,852	2,485,656	2,505,572	2,525,371
g. Cumulative Total	3,043,263	6,106,198	9,476,688	12,882,055	16,265,480	19,600,835	22,811,449	25,827,198	28,433,184	31,089,802	33,845,215	36,636,534	39,462,386	41,948,042	44,453,615	46,978,986
V. Total Construction Expenditures																
a. Annual	3,152,384	3,882,402	4,182,796	4,982,517	5,695,607	6,740,831	8,190,811	9,332,922	8,843,290	7,809,803	7,373,596	7,360,661	7,311,218	6,873,017	6,679,350	6,259,307
b. Cumulative	3,152,384	7,034,785	11,217,581	16,200,099	21,895,706	28,636,536	36,827,348	46,160,270	55,003,560	62,813,363	70,186,958	77,547,619	84,858,837	91,731,854	98,411,203	104,670,511
VI. % 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

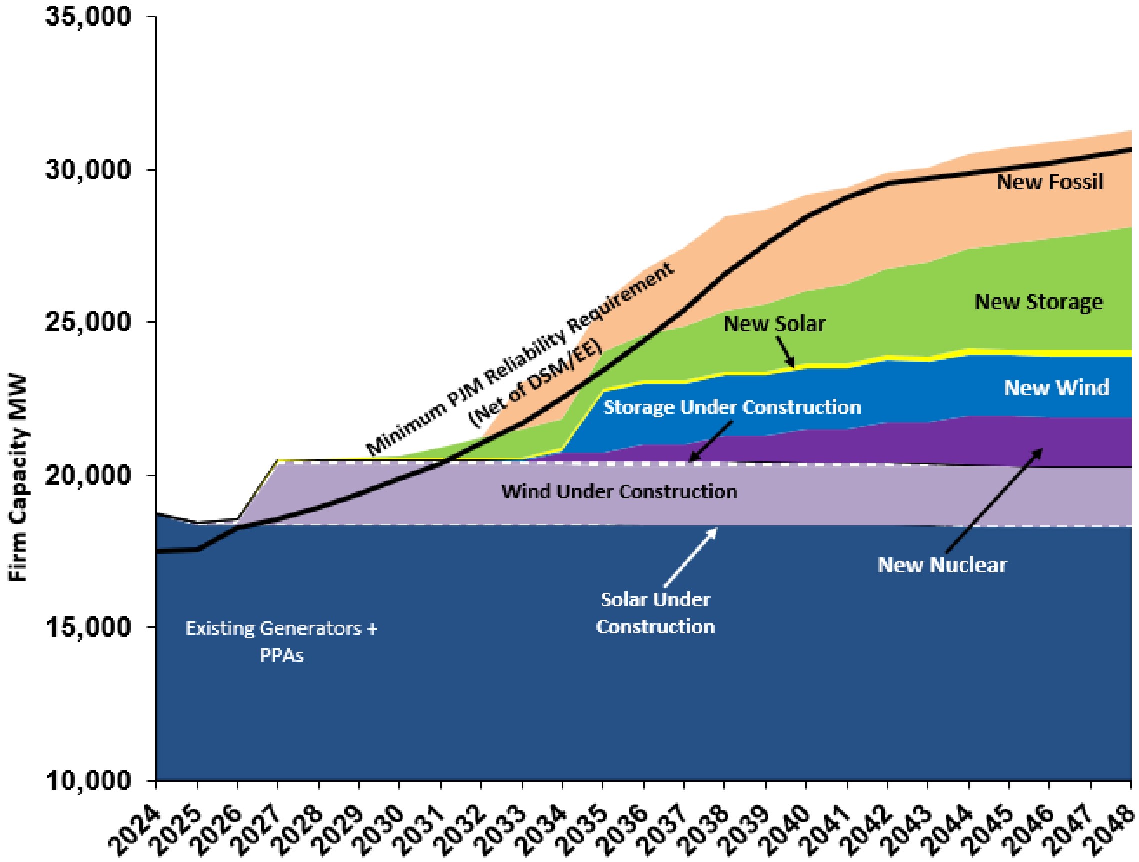
Appendix 5T: Winter Capacity Charts
Plan A



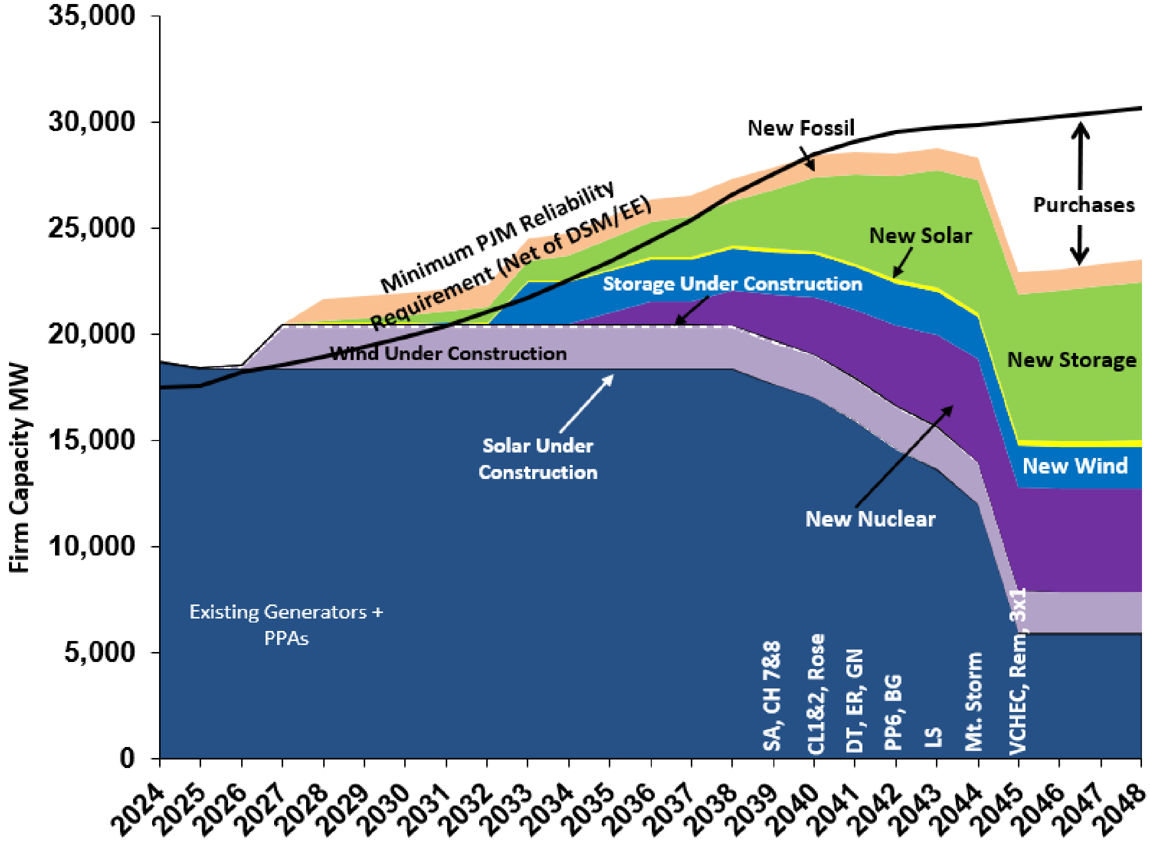
Appendix 5T: Winter Capacity Charts
Plan B



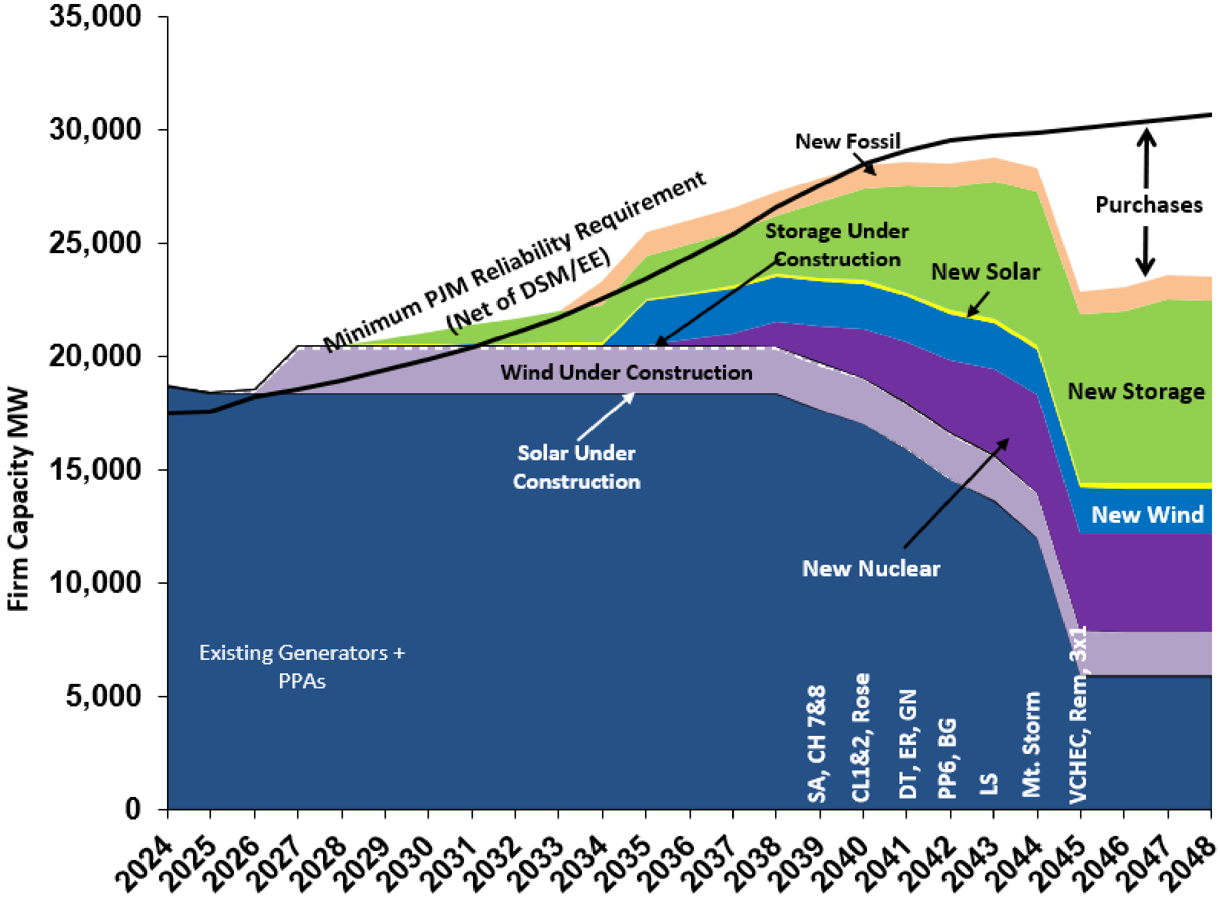
Appendix 5T: Winter Capacity Charts
Plan C



Appendix 5T: Winter Capacity Charts
Plan D



Appendix 5T: Winter Capacity Charts
Plan E



Appendix 6A – Description of Active DSM Programs

<u>Non-Residential Distributed Generation Program</u>

Branded Name: Distributed Generation
State: Virginia
Target Class: Non-Residential

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.

<u>Residential Appliance Recycling Program</u>

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides incentives to eligible residential customers to recycle specific types of qualifying freezers and refrigerators that are of specific of age and size. Appliance pick-up and proper recycling services are included.

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.

<u>Residential Efficient Products Marketplace Program</u>

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides eligible residential customers an incentive to purchase specific energy efficient appliances with a rebate through an online marketplace and through participating retail stores. The program offers rebates for the purchase of specific energy efficient appliances, including lighting efficiency upgrades such as A-line bulbs (prior to 2020), reflectors, decoratives, globes, retrofit kit and

fixtures, as well as other appliances such as freezers, refrigerators, clothes washers, dehumidifiers, air purifiers, clothes dryers, and dishwashers.

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.

Residential Home Energy Assessment Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
This Program provides qualifying residential customers with an incentive to install a variety of energy saving measures following completion of a walk-through home energy assessment. The energy saving measures include replacement of existing light bulbs with LED bulbs, heat pump tune-up, duct insulation/sealing, fan motors upgrades, installation of efficient faucet aerators and showerheads, water heater turndown, replacement of electric domestic hot water with heat pump water heater, heat pump upgrades (ducted and ductless), and water heater and pipe insulation.

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 this program is 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 Heating and Cooling Efficiency Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with incentives to implement new and upgrade existing high efficiency heating and cooling system 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 this program is 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.

<u>Non-Residential Window Film Program</u>

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with incentives to install solar reduction window film to lower their cooling bills and improve occupant comfort.

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 this program is 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.

<u>Non-Residential Small Manufacturing Program</u>

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with incentives for the installation of energy efficiency improvements, consisting of primarily compressed air systems measures for small manufacturing facilities.

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 this program is 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.

<u>Non-Residential Office Program</u>

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with incentives for the installation of energy efficiency improvements, consisting of recommissioning measures at smaller office facilities.

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 this program is 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.

<u>Residential Customer Engagement Program</u>

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides educational insights into the customer's energy consumption via a Home Energy Report (on-line and/or paper version). The Home Energy report is intended to provide periodic suggestions on how to save on energy based upon analysis of the customer's energy usage. Customers can opt-out of participating in the program at any time.

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.

<u>Residential Smart Thermostat Program (DR)</u>

Target Class: Residential
VA Program Type: Demand Response
NC Program Type: Demand Response

Program Description:
All residential customers who are not already participating in the Company's DSM Phase I Smart Cooling Rewards Program and who have a qualifying smart thermostat would be offered the opportunity to enroll in the peak demand response portion of the Program. Demand Response will be called by the Company during times of peak system demand throughout the year and thermostats of participating customers would be gradually adjusted to achieve a specified amount of load reduction while maintaining reasonable customer comfort and allowing customers to opt-out of specific events if they choose to do so.

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.

<u>Residential Smart Thermostat Program (EE)</u>

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides an incentive to customers to either purchase a qualifying smart thermostat and/or enroll in an energy efficiency program, which helps customers manage their daily heating and cooling energy usage by allowing remote optimization of their thermostat operation, and provides specific recommendations by e-mail or letter that customers can act on to realize additional energy savings. The Program is open to several thermostat manufacturers, makes, and models that meet or exceed the Energy Star requirements and have communicating technology. Rebates for the purchase of a smart thermostat are provided on a one-time basis; incentives for participation in remote thermostat management are provided on an annual basis. For those customers who are enrolled in thermostat management, additional energy-saving suggestions based on operational data specific to the customer's heating and cooling system are provided to the customer at least quarterly.

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.

Residential Electric Vehicle (EE/DR) Program

Target Class:	Residential
VA Program Type:	Energy Efficiency/ Demand Response
NC Program Type:	Energy Efficiency/Demand Response

Program Description:
This Program provides qualifying residential customers with an incentive to to purchase a Level 2 charger for their electric vehicle and who agree to enroll in the demand response ("DR") component of the proposed program. Demand response would be called by the Company during times of peak system demand throughout the year to reduce the electric vehicle charging load while encouraging customers to charge their vehicles during off-peak hours. Customers can opt-out of specific events if they choose to do so.

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.

Residential Electric Vehicle Peak Shaving Program

Target Class:	Residential
VA Program Type:	Peak-shaving
NC Program Type:	Peak-shaving

Program Description:
This Program provides an incentive for residential customers who already have a qualifying Level 2 charger and wish to participate in the demand response component only (no purchase incentive).

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.

Residential Electric Vehicle (EE/DR) Program

Target Class:	Residential
VA Program Type:	Energy Efficiency/ Demand Response
NC Program Type:	Energy Efficiency/Demand Response

Program Description:
This Program provides qualifying residential customers with an incentive to to purchase a Level 2 charger for their electric vehicle and who agree to enroll in the demand response ("DR") component of the proposed program. Demand response would be called by the Company during times of peak system demand throughout the year to reduce the electric vehicle charging load while encouraging customers to charge their vehicles during off-peak hours. Customers can opt-out of specific events if they choose to do so.

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.

Residential Energy Efficiency Kits Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
This Program provides qualifying residential customers with customers with new customer accounts the opportunity to receive Welcome Kits. The Welcome kit will initially include a Tier 1 advanced power strip and an educational insert informing customers about opportunities to manage their energy use and how to opt into receiving additional free measures by going online to the program website or calling the program hotline. To receive the additional measures, customers will have to confirm their address and account status and answer a few questions to confirm the measures will be of value in producing electric energy savings in the home. Additionally, customers will receive educational materials on proper use of each measure, energy use in general, and energy savings available through other Company DSM programs.

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.

Residential Home Retrofit Program

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program targets high users of electricity with an incentive to conduct a comprehensive and deep whole house diagnostic home energy assessment.

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.

Residential Manufactured Housing Program

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provide residential customers in manufactured housing with educational assistance and an incentive to install energy efficiency measures.

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.

Residential New Construction Program

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides incentives to home builders for the construction of new homes that are ENERGY STAR certified by directly recruiting existing networks of homebuilders and Home Energy Rating System (HERS) Raters to build and inspect ENERGY STAR Certified New Homes.

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.

Residential/Non-residential Multifamily Program

Target Class: Residential /Non-residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:

The Multifamily Program is designed to encourage investment in both residential and commercial service aspects of multifamily properties. The Program design is based on a whole building approach where the implementation vendor will identify as many cost-effective measure opportunities as possible in the entire building (both residential and commercial meter) and encourage property owners to address the measures as a bundle. This approach provides one-stop-shop programming for multifamily property owners with solutions to include direct install-in-unit measures and incentives for prescriptive efficiency improvements. The Program will identify, track and report residential (in-unit) and commercial (common space) savings separately according to the account type.

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.

Non-Residential Midstream EE Products Program

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:

This Program consists of enrolling equipment distributors into the Program through an agreement to provide point-of-sales data in an agreed upon format each month. These monthly data sets will contain, at minimum, the data necessary to validate and quantify the eligible equipment that has been delivered for sale in the Company's service territory. In exchange for the data sets, the distributor will discount the rebate-eligible items sold to end customers. This Program aims to increase the availability and uptake of efficient equipment for the Company’s non-residential customers.

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.

Non-Residential New Construction Program

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:

This Program provides qualifying facility owners with incentives to install energy efficient measures in their new construction project.

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.

Small Business Improvement Enhanced

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
This Program provides 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 would be required to meet certain size and 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 this program is 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.

Residential Smart Home Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
This Program provides the Company's residential customers a suite of smart home products that provide seamless integration in the home. The program will deliver the energy efficient measures bundled in two versions of a Smart Home Kit, so that customers can benefit from a fully integrated set of compatible smart products.

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.

Residential Virtual Audit Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
This Program offers residential customers a self-directed home energy assessment using an audit software, completed entirely by the customer, with no trade ally entering the home. Customers would be directed to a website or toll-free number where they would answer a set of questions with answers specific to the conditions and systems in their home with aids to help them answer accurately.

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.

<u>Residential Water Savings (EE) Program</u>

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
Program is designed to give the Company's residential customers control over their water related energy use. The proposed Program leverages the installation of smart communicating water heating and pool pump technologies to facilitate more efficient operation while reducing overall electricity usage and peak demand response. Customers have the option to purchase a qualified program product online, in-store, equipment distributor, or through qualified local trade allies.

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.

<u>Residential Water Savings (Demand Response) Program</u>

Target Class: Residential
VA Program Type: Demand Response
NC Program Type: Demand Response

Program Description:
All residential customers who purchase and install a qualified product (EE component) will be offered the opportunity to enroll in the peak demand reduction (DR) component of the DR Program. Additionally, customers who have previously purchased a qualifying product and who have the eligible products installed, will be offered the opportunity to enroll in the DR component of the Program. Customers would be allowed to opt-out of a certain number of events.

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.

Residential Income and Age Qualifying Program

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

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.

Non-Residential Agricultural Program

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with incentives to implement specific energy efficiency measures to help agribusinesses replace aging, inefficient equipment and systems with new, energy-efficient technologies. The Program is designed to help agricultural customers make their operations more energy-efficient by providing incentives for efficient agricultural equipment and lighting specifically used in agricultural applications.

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 this program is 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 Building Automation

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with incentives to install new building automation systems in facilities that do not have centralized controls or have an antiquated system that requires full replacement.

Program Marketing:
Marketing is handled by the Company's implementation vendor.

<u>Non-Residential Building Optimization</u>

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with incentives for the installation of energy efficiency improvement, consisting of recommissioning measures. The Program seeks to capture energy savings through control system audits and tune-up measures in facilities with Building Energy Management Systems.

Program Marketing:
Marketing is handled by the Company's implementation vendor.

<u>Non-Residential Engagement Program</u>

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
The Program engages commercial buildings in energy management best practices that increase awareness of operational and behavioral energy savings opportunities. The Program would educate and train businesses' facility management staff on ways to achieve energy savings through optimization of building energy performance and integrating ongoing commissioning best practices into their operations.

Program Marketing:
Marketing is handled by the Company's implementation vendor.

<u>Non-Residential Enhanced Prescriptive Program</u>

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with an incentive for the installation of refrigeration, commercial kitchen equipment, HVAC improvements and maintenance and installation of other program specific, energy efficiency measures.

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 this program is 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.

<u>Residential Income and Age Qualifying Home Energy Report Program</u>

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program would offer the opportunity for low income qualifying customers to save energy in their homes while providing incentives for verified energy 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.

<u>Small Business Behavioral Program</u>

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program would provide small businesses with customized business energy report (BER), either digitally or through mail, with energy saving tips, forecasting, and recommendations. The proposed program design also incorporates higher touch customer engagement, which engages small business owners in a quick online experience to learn more about their energy usage, find customized ways to save energy, provide data to the program to improve energy savings personalization for each business segment and cross-promote other DSM programs in addition to connecting the customer with the program design vendor's energy advisors.

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.

<u>Non-Residential Data Center and Server Room Program</u>

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides qualifying non-residential customers with an incentive to install energy efficiency measures related to equipment in and operation of data centers and server rooms.

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 this program is 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.

<u>Non-Residential Lighting Systems & Controls Program</u>
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

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 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 this program is 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.

<u>Non-Residential Health Care Program</u>
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides would target the health care customer segment and will provide those qualifying non-residential customers with incentives to install energy efficiency measures.

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 this program is 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 Hotel and Lodging Program

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program provides would target the target the hotel and lodging customer segment and would provide those qualifying non-residential customers with incentives to install energy efficiency measures.

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 this program is 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.

Voltage Optimization

Target Class: Non-Residential/Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
Voltage optimization ("VO") will reduce energy consumption for a wide cross-section of customers. Control of the program will be implemented on Dominion Energy equipment, but 98-99% of the energy reduction occurs behind the meter at the end-use loads. Customers will see benefits in reduced bills due to reductions in both energy consumption and peak demand.

Program Marketing:
Not Applicable

Residential Peak Time Rebate Program

Target Class: Residential
VA Program Type: Energy Efficiency/Demand Response
NC Program Type: Energy Efficiency/Demand Response

Program Description:
This Program would enable residential customers to reduce their energy usage consumption during peak time periods as called upon by the Company. During peak time rebate event days, proposed program design will alert customers with text messaging, emails or outbound telemarketing voicemail, as well as by utilizing the Company's dominionenergy.com website with banner announcements informing participants an event is in progress

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.

<u>Non-Residential Custom Program</u>

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
This Program would provide qualifying non-residential customers, with a focus on larger facilities with demand greater than 300 kW, with the technical support and incentives needed to pursue non-standard, more complex energy efficiency projects. Qualifying non-residential customers develop tailored projects that best meet their unique facility and organizational goals while achieving savings from a diverse mix of measures

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 this program is 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.

<u>Residential Electric Vehicle (EV) Pilot Program</u>

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
The proposed program pilot would run in parallel with the current Electric Vehicle Demand Response Program. Instead of communicating with the electric vehicle charger, the proposed pilot program would allow for integration with newer technology onboard vehicle telematics to capture charging data and control the charging rate during load curtailment events dispatched by the Company.

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.

<u>Residential Income and Age Qualifying Home Improvement Program Bundle</u>

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
The proposed bundled version of the Residential Income and Age Qualifying Home Improvement Program combines the Company's existing HB 2789 HVAC Program measures in addition to the Phase IX and X low-income program measures while adding several new program measures and creating a bundled income qualifying program that would provide income and age qualifying residential customers with in-home energy assessments and installation of select energy-saving measures. Energy assessments and installations will be conducted by qualified, local weatherization service providers ("WSP") who currently offer weatherization related services through the Virginia Department of Housing and Community Development and have been approved by the Income and Age Qualifying Program to complete assessments and install the selected energy-saving products.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

<u>Non-residential Income and Age Qualifying Home Improvement Program Bundle</u>

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
Program would offer installation of select energy-saving measures to be installed in properties that house low-income and aging residents, but the electric bill is paid by the property, rather than the individual resident. This would include housing authority and master metered properties, assisted living residences, and nursing homes.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

<u>Non-residential Prescriptive Program Bundle</u>

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
The proposed program design would offer a more comprehensive program bundle that would incorporate the Company's expiring DSM Phase VII Non-residential Heating and Cooling Efficiency, Non-residential Manufacturing and Non-residential Window Film Programs into the overarching DSM Phase IX Non-residential Enhanced Prescriptive Program offering. The consolidation of various program measures into a more enhanced version of the Phase IX Non-residential Prescriptive Program would allow the Company to consolidate programs and offer qualifying non-residential customers the ease of implementing a wide variety of energy efficiency measures.

This Program would provide qualifying non-residential customers with incentives for the installation of refrigeration, commercial kitchen equipment, HVAC improvements, window film installation and maintenance and installation of other program specific, energy efficiency measures.

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 this program is 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.

Residential Retrofit Program Bundle

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
The proposed program re-design incorporates key program measures from the Company's Phase VII Residential Home Energy Assessment Program and measures from the existing Home Retrofit Program.

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 this program is 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 6B - Approved Programs Non-Coincidental Peak Savings
(kW) (System Level)

Phase	Acronym	Programs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
I	CHVC	Commercial HVAC Upgrade Program	2,885	2,883	2,883	1,983	394	0	0	0	0	0	0	0	0	0	0	0
I	CLGT	Commercial Lighting Program	217	216	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I	EALI	Low Income Program	2,672	2,654	1,912	1,012	690	259	75	0	0	0	0	0	0	0	0	0
II	CDUC	Commercial Duct Testing & Sealing Program	29,449	29,432	29,430	29,420	29,491	29,464	29,435	29,439	29,430	29,439	29,488	29,449	29,435	29,441	29,420	29,414
II	DG	Commercial Distributed Generation Program	10,014	11,326	12,637	13,948	15,260	15,742	15,809	15,873	15,936	15,997	16,058	16,117	16,176	16,244	16,316	16,389
II	EACI	Commercial Energy Audit Program	950	660	0	0	0	0	0	0	0	0	0	0	0	0	0	0
II	EAR1	Residential Home energy Check Up	9,928	9,078	5,061	2,701	257	0	0	0	0	0	0	0	0	0	0	0
II	RDUC	Residential Duct Testing & Sealing Program	408	408	408	408	408	408	408	408	405	373	303	66	9	0	0	0
II	RHEH	Heat Pump Upgrade Program	6,928	6,928	6,928	6,928	6,928	6,826	3,434	628	398	87	0	0	0	0	0	0
III	CHV2	Non-Residential Heating and Cooling Efficiency Program	19,852	19,806	19,806	19,812	19,884	19,875	19,819	19,537	17,392	14,809	9,440	2,386	0	0	0	0
III	CLT2	Non-Residential Lighting Systems & Controls Program	45,942	44,216	35,778	25,261	14,041	6,722	96	0	0	0	0	0	0	0	0	0
III	CSWF	Non-Residential Window Film	6,851	6,865	2,393	2,122	1,305	64	3	0	0	0	0	0	0	0	0	0
IV	EAL3	Income and Age Qualifying Home Improvement Program	2,786	2,690	2,786	2,786	2,785	2,690	2,786	2,437	1,376	733	733	595	195	104	0	0
IV	RARC	Residential Appliance Recycling Program	1,803	1,125	292	0	0	0	0	0	0	0	0	0	0	0	0	0
V	RLED	Residential Retail LED Lighting Program (NC only)	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,536	1,111
V	SBIP	Small Business Improvement Program	14,663	14,621	14,631	14,631	14,698	14,686	14,630	14,632	14,062	10,111	5,787	2,627	476	0	0	0
VI	CNRP	Non-Residential Prescriptive Program	16,765	16,704	15,304	12,605	6,917	926	0	0	0	0	0	0	0	0	0	0
VII	CHV3	Non-Residential Heating and Cooling Efficiency Program	44,822	54,421	56,858	59,334	61,848	64,088	64,088	64,088	64,088	64,088	64,088	64,088	64,088	64,088	61,833	34,776
VII	CLT3	Non-Residential Lighting Systems & Controls Program	6,809	6,802	6,803	6,804	6,813	6,811	6,804	6,803	6,094	2,927	2,647	0	0	0	0	0
VII	CSW2	Non-Residential Window Film Program	359	388	405	424	442	444	444	444	444	394	215	64	48	31	14	0
VII	CTSM	Non-Residential Small Manufacturing Program	2,865	2,987	3,110	3,233	3,356	3,356	3,356	3,356	3,356	3,356	3,356	3,229	1,800	480	357	235
VII	CTSO	Non-Residential Office Program	4,123	5,353	5,601	6,609	8,919	10,107	8,588	5,984	4,754	4,506	3,498	1,302	0	0	0	0
VII	RAR2	Residential Appliance Recycling Program (v2)	1,235	1,479	1,546	1,613	1,676	1,705	1,705	1,286	623	231	165	98	43	0	0	0
VII	RCEB	Residential Customer Engagement Program	20,708	19,394	18,057	19,444	21,584	18,650	0	0	0	0	0	0	0	0	0	0
VII	REEC	Residential Efficient Products Marketplace Program	48,032	48,042	48,038	48,037	48,027	48,027	48,039	48,040	48,038	48,032	48,027	48,032	48,039	45,143	27,248	11,166
VII	RTHO	Home Energy Assessment	48,073	50,396	52,318	54,455	56,634	57,365	57,365	57,365	57,365	57,365	57,365	54,568	30,592	8,231	6,189	4,107
VIII	CEEP	Non-Residential EE Products	2,122	3,462	4,803	5,439	5,575	5,632	5,632	5,632	5,632	5,632	5,632	5,632	5,632	5,632	5,632	4,850
VIII	CHVLI	Non-residential Heating & Cooling HB 2789	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
VIII	CMFP	Commercial Multifamily Program	791	1,244	1,696	1,906	1,950	1,968	1,968	1,968	1,694	1,224	770	387	65	31	0	0
VIII	CNCR	Non-Residential New Construction	1,922	4,333	6,499	6,629	6,759	6,817	6,817	6,817	6,817	6,817	6,817	6,817	6,817	6,817	6,817	6,817
VIII	REVDR	Residential Electric Vehicle (DR)	589	1,239	2,351	3,521	4,714	5,057	5,108	5,161	5,216	5,262	5,314	5,358	5,405	5,467	5,528	5,591
VIII	REVEE	Residential Electric Vehicle (EE)	77	152	266	325	332	335	335	335	335	313	261	195	115	12	6	0
VIII	RHRF	Residential Home Retrofit	2,218	3,869	5,727	7,739	7,907	8,064	8,064	8,064	8,064	8,064	8,064	8,064	8,064	8,064	8,064	8,064
VIII	RHVC	Residential Low-Income HVAC HB 2789	2,745	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	3,835	1,834	175	174	174
VIII	RKTS	Residential EE Kits	1,177	1,766	2,354	2,413	2,473	2,310	1,749	1,188	627	109	52	29	29	29	20	20
VIII	RMFP	Residential Multifamily Program	212	317	423	445	456	464	464	464	464	464	464	464	464	464	464	440
VIII	RMHP	Residential Manufactured Housing Program	272	414	556	568	581	586	586	586	586	586	586	586	586	571	440	297
VIII	RNCR	Residential New Construction	5,658	9,537	13,524	15,401	15,774	15,931	15,931	15,931	15,931	15,931	15,931	15,931	15,931	15,931	15,931	15,931
VIII	RTDR	Residential Smart Thermostat (DR)	38,070	50,597	61,205	65,322	66,628	67,580	68,326	69,038	69,723	70,385	71,027	71,653	72,268	73,003	73,806	74,617
VIII	RTEB	Residential Smart Thermostat Program (Behavioral)	1,539	1,042	970	729	104	97	0	0	0	0	0	0	0	0	0	0
VIII	RTEE	Residential Smart Thermostat (EE)	2,424	3,739	5,584	7,618	7,788	7,947	7,947	7,805	6,098	4,288	2,363	329	159	0	0	0
VIII	SBI2	Non Residential Small Business Improvement Enhanced Program	1,864	2,983	4,118	4,665	4,782	4,831	4,831	4,831	4,831	4,831	4,831	4,831	4,831	4,831	4,160	3,011
IX	CAGR	Non-Residential Agricultural	1,203	1,786	2,369	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,774	2,176
IX	CBAS	Non-Res Building Automation Program	6,441	9,802	13,163	16,524	17,112	17,140	17,140	17,140	17,140	17,140	17,140	17,140	17,140	17,140	17,140	17,140
IX	CBOT	Non-Res Building Optimization	7,854	11,951	16,049	20,146	20,863	20,897	19,078	15,275	11,472	7,669	3,866	349	0	0	0	0
IX	CENG	Non-Res Engagement Program	6,674	10,157	13,639	17,121	17,747	17,778	16,230	12,998	9,766	6,535	3,303	312	0	0	0	0
IX	CNR2	Non-Residential Enhanced Prescriptive Program	5,748	9,033	12,318	15,603	17,202	15,360	11,959	8,558	5,394	2,524	228	0	0	0	0	0
IX	EAL4	Enhancement of Residential Income and Age Qualifying	963	1,488	2,058	2,708	3,261	3,315	3,315	3,315	3,315	3,315	3,207	2,557	1,907	1,257	607	54
IX	EALS	Low-Income HVAC HB 2789 (Solar Component)	2,167	3,406	4,309	4,309	4,309	4,309	4,309	4,309	4,309	4,309	4,309	4,309	4,309	4,309	4,309	4,309
IX	RSMH	Residential Smart Home Program	4,370	8,093	12,787	18,484	21,371	21,547	21,547	21,547	21,547	21,547	20,315	17,586	13,802	9,669	4,668	286
IX	RVAU	Residential Virtual Audit Program	9,037	13,809	18,075	22,129	24,096	24,295	24,295	24,295	24,295	24,295	24,295	24,295	24,295	24,295	24,295	24,295
IX	RWDR	Residential Water Savings (DR) Program	1,057	2,919	6,520	12,600	19,446	21,348	21,582	21,805	22,021	22,230	22,435	22,636	22,835	23,079	23,338	23,601
IX	RWEE	Residential Water Savings (EE) Program	2,107	4,960	9,708	16,597	20,069	20,235	20,235	20,235	20,235	20,235	20,235	19,668	18,128	15,275	10,526	3,638
X	CDAC	Non Res Data Center and Server Rooms	109	308	718	1,257	1,795	1,827	1,827	1,827	1,827	1,827	1,827	1,827	1,827	1,800	1,673	1,451
X	CHA4	Non-Residential Hotel and Lodging	3,280	8,217	14,352	21,030	26,832	28,200	28,200	28,200	28,200	28,200	28,200	28,200	26,830	22,264	16,496	9,997
X	CHT4	Non-Residential Health Care	4,069	10,192	17,815	26,111	33,311	35,009	35,009	35,009	35,009	35,009	35,009	35,009	35,009	35,009	33,309	27,646
X	CIAQ	Non Res IAQ Healthcare and Rental Property Owners	12	25	38	54	71	86	86	86	86	86	86	86	86	86	83	66
X	CLT4	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	13,738	26,215	41,194	56,174	71,154	74,899	74,899	74,899	74,899	74,899	74,899	68,705	53,983	39,260	24,930	11,923
X	CSBB	Small Business Behavioral	6,696	9,373	8,624	7,934	7,299	3,304	0	0	0	0	0	0	0	0	0	0
X	REE2	Residential Efficient Products Marketplace Program	52,440	51,076	52,895	54,750	56,643	56,643	56,643	56,643	56,643	56,643	56,643	56,643	56,643	56,643	56,643	56,643
X	RIAQ	Residential IAQ Enhancements	23	47	73	99	125	129	129	129	129	129	129	129	129	129	129	129
X	RLMI	Residential IAQ Home Energy Report	1,117	1,614	1,614	1,614	1,614	790	0	0	0	0	0	0	0	0	0	0
X	VOPT	Voltage Optimization	6,724	23,426	41,866	62,947	84,029	105,110	126,112	138,413	141,397	142,136	142,875	143,615	144,354	145,093	145,832	146,572
	VOPT NONJU	VOPT for Non-Jurisdictional class	785	2,999	5,595	8,192	10,789	13,379	15,973	17,182	17,438	17,526	17,608	17,699	17,802	17,903	17,984	18,076
		Total	**549,084**	**660,121**	**754,500**	**851,282**	**915,926**	**930,039**	**911,816**	**908,612**	**893,508**	**871,212**	**848,495**	**812,101**	**756,784**	**702,603**	**648,696**	**565,014**

Appendix 6C - Approved Programs Coincidental Summer Peak Savings (kW) (System Level)

Phase	Acronym	Programs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	CHVC	Commercial HVAC Upgrade Program	2,885	2,883	2,883	1,983	207	0	0	0	0	0	0	0	0	0	0	0
1	CLGT	Commercial Lighting Program	199	121	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	EALI	Low Income Program	1,355	1,191	757	453	216	57	6	0	0	0	0	0	0	0	0	0
2	CDUC	Commercial Duct Testing & Sealing Program	29,449	29,432	29,430	29,420	29,491	29,464	29,435	29,439	29,430	29,439	29,488	29,449	29,435	29,441	29,420	29,414
2	DG	Commercial Distributed Generation Program	9,446	10,696	11,947	13,197	14,448	15,007	15,071	15,132	15,192	15,251	15,308	15,365	15,421	15,485	15,553	15,623
2	EACI	Commercial Energy Audit Program	677	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	EAR1	Residential Home energy Check Up	6,675	5,502	2,827	940	0	0	0	0	0	0	0	0	0	0	0	0
2	RDUC	Residential Duct Testing & Sealing Program	170	170	170	170	170	170	170	170	164	159	107	60	0	0	0	0
2	RHEH	Heat Pump Upgrade Program	4,002	4,002	4,002	4,002	4,002	3,383	1,449	556	169	0	0	0	0	0	0	0
3	CHV2	Non-Residential Heating and Cooling Efficiency Program	12,489	12,473	12,473	12,471	12,508	12,498	12,477	10,414	6,725	3,260	2,121	4	0	0	0	0
3	CLT2	Non-Residential Lighting Systems & Controls Program	43,686	38,785	30,356	19,427	10,906	189	0	0	0	0	0	0	0	0	0	0
3	CSWF	Non-Residential Window Film	6,851	6,865	2,393	2,122	1,305	27	0	0	0	0	0	0	0	0	0	0
4	EAL3	Income and Age Qualifying Home Improvement Program	1,562	1,562	1,562	1,562	1,561	1,562	1,562	1,139	391	285	285	186	56	0	0	0
4	RARC	Residential Appliance Recycling Program	1,568	823	1	0	0	0	0	0	0	0	0	0	0	0	0	0
5	RLED	Residential Retail LED Lighting Program (NC only)	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	305
5	SBIP	Small Business Improvement Program	13,437	13,400	13,408	13,408	13,470	13,458	13,408	13,409	11,827	6,862	4,162	1,487	0	0	0	0
6	CNRP	Non-Residential Prescriptive Program	16,690	16,625	15,145	12,272	6,917	0	0	0	0	0	0	0	0	0	0	0
7	CHV3	Non-Residential Heating and Cooling Efficiency Program	5,450	7,065	7,378	7,696	8,018	8,154	8,154	8,154	8,154	8,154	8,154	8,154	8,154	8,154	6,145	2,703
7	CLT3	Non-Residential Lighting Systems & Controls Program	6,073	6,067	6,068	6,069	6,077	6,076	6,069	6,068	3,395	2,472	1,030	0	0	0	0	0
7	CSW2	Non-Residential Window Film Program	200	259	271	283	295	300	300	300	300	226	100	40	29	17	5	0
7	CTSM	Non-Residential Small Manufacturing Program	2,045	2,647	2,758	2,869	2,979	3,026	3,026	3,026	3,026	3,026	3,026	2,272	981	378	268	157
7	CTSO	Non-Residential Office Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	RAR2	Residential Appliance Recycling Program (v2)	1,126	1,460	1,526	1,593	1,661	1,689	1,689	1,275	563	229	164	97	29	0	0	0
7	RCEB	Residential Customer Engagement Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	REEC	Residential Efficient Products Marketplace Program	15,721	15,724	15,723	15,722	15,719	15,719	15,723	15,723	15,723	15,721	15,719	15,721	15,723	11,468	6,122	515
7	RTHO	Home Energy Assessment	2,548	3,302	3,440	3,581	3,725	3,785	3,785	3,785	3,785	3,785	3,785	2,850	1,237	483	345	204
8	CEEP	Non-Residential EE Products	2,089	3,409	4,729	5,355	5,489	5,545	5,545	5,545	5,545	5,545	5,545	5,545	5,545	5,545	5,545	4,776
8	CHVLI	Non-residential Heating & Cooling HB 2789	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	CMFP	Commercial Multifamily Program	743	1,212	1,682	1,902	1,946	1,965	1,965	1,965	1,691	1,222	753	283	62	18	0	0
8	CNCR	Non-Residential New Construction	1,396	3,061	4,994	5,867	5,983	6,031	6,031	6,031	6,031	6,031	6,031	6,031	6,031	6,031	6,031	6,031
8	REVDR	Residential Electric Vehicle (DR)	165	353	648	998	1,354	1,514	1,531	1,547	1,562	1,577	1,592	1,606	1,620	1,637	1,655	1,674
8	REVEE	Residential Electric Vehicle (EE)	3	6	10	12	12	12	12	12	12	11	9	7	3	0	0	0
8	RHRF	Residential Home Retrofit	2,028	3,665	5,424	6,235	6,370	6,427	6,427	6,427	6,427	6,427	6,427	6,427	6,427	6,427	6,427	6,427
8	RHVC	Residential Low-Income HVAC HB 2789	680	858	858	858	858	858	858	858	858	858	858	608	179	151	150	150
8	RKTS	Residential EE Kits	262	428	594	673	689	600	434	268	103	24	12	12	12	12	6	6
8	RMFP	Residential Multifamily Program	72	117	163	184	189	190	190	190	190	190	190	190	190	190	190	164
8	RMHP	Residential Manufactured Housing Program	46	76	106	121	123	124	124	124	124	124	124	124	124	108	79	48
8	RNCR	Residential New Construction	5,658	9,537	13,524	15,401	15,774	15,931	15,931	15,931	15,931	15,931	15,931	15,931	15,931	15,931	15,931	15,931
8	RTDR	Residential Smart Thermostat (DR)	35,103	47,052	57,318	61,897	63,135	64,082	64,792	65,470	66,123	66,753	67,363	67,958	68,543	69,226	69,987	70,757
8	RTEB	Residential Smart Thermostat Program (Behavioral)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	RTEE	Residential Smart Thermostat (EE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	SBI2	Non Residential Small Business Improvement Enhanced Program	1,710	2,789	3,869	4,382	4,492	4,538	4,538	4,538	4,538	4,538	4,538	4,538	4,538	4,538	3,908	2,828
9	CAGR	Non-Residential Agricultural	239	385	530	676	736	736	736	736	736	736	736	736	736	736	646	497
9	CBAS	Non-Res Building Automation Program	639	1,043	1,447	1,851	2,043	2,060	2,060	2,060	2,060	2,060	2,060	2,060	2,060	2,060	2,060	2,060
9	CBOT	Non-Res Building Optimization	780	1,272	1,764	2,257	2,491	2,511	2,224	1,732	1,239	747	254	21	0	0	0	0
9	CENG	Non-Res Engagement Program	663	1,081	1,500	1,918	2,118	2,136	1,892	1,474	1,055	637	218	18	0	0	0	0
9	CNR2	Non-Residential Enhanced Prescriptive Program	5,364	8,752	12,140	15,528	17,138	15,303	11,915	8,527	5,138	1,750	141	0	0	0	0	0
9	EAL4	Enhancement of Residential Income and Age Qualifying	220	359	497	636	702	708	708	708	708	708	627	488	349	211	72	6
9	EALS	Low-Income HVAC HB 2789 (Solar Component)	1,625	2,652	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080
9	RSMH	Residential Smart Home Program	2,637	5,156	8,379	12,305	14,227	14,344	14,344	14,344	14,344	14,344	13,524	11,707	9,188	5,965	2,039	117
9	RVAU	Residential Virtual Audit Program	8,929	13,644	17,858	21,864	23,807	24,003	24,003	24,003	24,003	24,003	24,003	24,003	24,003	24,003	24,003	24,003
9	RWDR	Residential Water Savings (DR) Program	894	2,560	5,840	11,475	18,299	21,308	21,543	21,768	21,985	22,195	22,401	22,603	22,802	23,036	23,295	23,557
9	RWEE	Residential Water Savings (EE) Program	2,085	4,909	9,609	16,427	19,864	20,028	20,028	20,028	20,028	20,028	20,028	19,467	17,943	15,119	10,419	3,601
10	CDAC	Non Res Data Center and Server Rooms	37	130	320	605	920	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,016	921	731
10	CHA4	Non-Residential Hotel and Lodging	2,551	7,304	13,293	19,899	25,919	28,200	28,200	28,200	28,200	28,200	28,200	28,200	25,802	20,896	14,907	8,301
10	CHT4	Non-Residential Health Care	3,165	9,061	16,498	24,707	32,180	35,009	35,009	35,009	35,009	35,009	35,009	35,009	35,009	35,009	32,034	25,948
10	CIAQ	Non Res IAQ Healthcare and Rental Property Owners	3	7	12	16	21	23	23	23	23	23	23	23	23	23	20	15
10	CLT4	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	9,036	23,055	37,616	52,178	66,739	72,806	72,806	72,806	72,806	72,806	72,806	64,312	49,751	35,190	20,628	6,067
10	CSBB	Small Business Behavioral	5,827	8,952	8,236	7,577	6,971	2,803	0	0	0	0	0	0	0	0	0	0
10	REE2	Residential Efficient Products Marketplace Program	11,836	13,742	14,235	14,737	16,019	16,246	15,465	15,465	15,465	15,465	16,246	16,246	15,465	15,465	15,465	16,246
10	RIAQ	Residential IAQ Enhancements	1	3	5	7	8	9	9	9	9	9	9	9	9	9	9	9
10	RLMI	Residential IAQ Home Energy Report	996	1,605	1,605	1,605	1,605	669	0	0	0	0	0	0	0	0	0	0
10	VOPT	Voltage Optimization (DVI)	4,922	20,664	41,623	62,582	83,541	104,501	125,380	137,610	140,577	141,312	142,047	142,782	143,517	144,252	144,986	145,721
80	VOPT NONJU	VOPT for Non-Jurisdictional class	567	2,383	4,795	7,208	9,620	12,026	14,438	15,844	16,185	16,267	16,343	16,428	16,523	16,617	16,693	16,777
		Total	**297,970**	**383,035**	**460,017**	**532,957**	**588,836**	**602,635**	**616,312**	**622,669**	**612,378**	**599,226**	**592,324**	**573,884**	**548,277**	**518,622**	**479,743**	**434,450**

Appendix 6D - Approved Programs Energy Savings
(MWh) (System Level)

Phase	Acronym	Programs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
I	CHVC	Commercial HVAC Upgrade Program	6,720	6,720	6,645	4,705	569	0	0	0	0	0	0	0	0	0	0	0
I	CLGT	Commercial Lighting Program	833	553	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I	EALI	Low Income Program	7,301	6,612	4,496	2,776	1,672	602	85	0	0	0	0	0	0	0	0	0
II	CDUC	Commercial Duct Testing & Sealing Program	75,536	75,535	75,536	75,537	75,537	75,536	75,535	75,536	75,536	75,537	75,536	75,536	75,535	75,536	75,532	75,142
II	DG	Commercial Distributed Generation Program	475	538	601	664	727	756	759	763	766	768	771	774	777	780	784	787
II	EACI	Commercial Energy Audit Program	5,685	148	0	0	0	0	0	0	0	0	0	0	0	0	0	0
II	EAR1	Residential Home energy Check Up	35,308	29,029	15,104	5,862	101	0	0	0	0	0	0	0	0	0	0	0
II	RDUC	Residential Duct Testing & Sealing Program	937	937	937	937	937	937	937	936	909	856	539	166	5	0	0	0
II	RHEH	Heat Pump Upgrade Program	14,487	14,487	14,487	14,487	14,463	11,962	5,345	1,936	879	32	0	0	0	0	0	0
III	CHV2	Non-Residential Heating and Cooling Efficiency Program	35,090	35,088	35,090	35,090	35,091	35,090	35,016	30,213	21,382	13,052	7,051	708	0	0	0	0
III	CLT2	Non-Residential Lighting Systems & Controls Program	216,102	195,713	151,177	97,793	55,853	4,717	66	0	0	0	0	0	0	0	0	0
III	CSWF	Non-Residential Window Film	5,563	5,563	2,043	1,779	952	73	1	0	0	0	0	0	0	0	0	0
IV	EAL3	Income and Age Qualifying Home Improvement Program	10,795	10,795	10,795	10,795	10,795	10,795	10,675	8,300	4,224	2,825	2,757	1,801	515	150	0	0
IV	RARC	Residential Appliance Recycling Program	10,977	5,933	526	0	0	0	0	0	0	0	0	0	0	0	0	0
V	RLED	Residential Retail LED Lighting Program (NC only)	7,268	7,268	7,268	7,268	7,268	7,268	7,268	7,268	7,268	7,268	7,268	7,268	7,268	7,268	6,967	3,167
V	SBIP	Small Business Improvement Program	54,129	54,129	54,129	54,129	54,129	54,129	54,129	54,077	47,021	29,928	16,058	5,957	162	0	0	0
VI	CNRP	Non-Residential Prescriptive Program	45,429	44,150	38,708	33,007	13,956	1,684	0	0	0	0	0	0	0	0	0	0
VII	CHV3	Non-Residential Heating and Cooling Efficiency Program	30,982	42,755	44,359	46,184	48,038	48,824	49,035	49,036	49,036	49,077	48,850	48,850	48,449	47,359	37,700	17,884
VII	CLT3	Non-Residential Lighting Systems & Controls Program	55,605	55,685	55,645	55,645	55,645	55,594	55,645	55,291	39,196	20,570	7,909	0	0	0	0	0
VII	CSW2	Non-Residential Window Film Program	1,001	1,233	1,273	1,316	1,359	1,376	1,379	1,251	1,099	836	376	147	106	63	20	0
VII	CTSM	Non-Residential Small Manufacturing Program	11,525	15,356	15,957	16,594	17,232	17,471	17,524	17,524	17,524	17,523	17,481	13,382	5,965	2,210	1,567	930
VII	CTSO	Non-Residential Office Program	3,899	4,669	4,822	5,459	6,907	6,483	5,385	3,750	2,984	2,828	2,190	738	0	0	0	0
VII	RAR2	Residential Appliance Recycling Program (v2)	9,085	11,568	12,003	12,471	12,824	12,019	11,821	9,053	4,076	1,620	1,157	690	213	0	0	0
VII	RCEB	Residential Customer Engagement Program	57,195	53,670	49,739	54,996	60,529	29,201	0	0	0	0	0	0	0	0	0	0
VII	REEC	Residential Efficient Products Marketplace Program	187,321	187,320	187,321	187,321	187,322	187,321	187,320	187,321	187,321	187,322	187,321	187,321	187,320	150,744	78,792	14,249
VII	RTHO	Home Energy Assessment	119,474	151,838	156,833	162,301	167,879	170,058	170,448	170,448	170,448	169,919	164,269	115,045	50,602	19,038	13,616	8,147
VIII	CEEP	Non-Residential EE Products	3,916	6,416	8,890	10,128	10,379	10,474	10,493	10,493	10,493	10,493	10,468	10,413	10,431	10,450	10,431	9,049
VIII	CHVLI	Non-residential Heating & Cooling HB 2789	4	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5
VIII	CMFP	Commercial Multifamily Program	4,510	7,442	10,341	11,809	12,082	12,237	12,207	12,207	10,612	7,720	4,780	1,866	397	125	0	0
VIII	CNCR	Non-Residential New Construction	5,397	12,000	19,695	23,409	23,873	24,077	24,080	24,080	24,080	24,174	24,029	24,029	24,080	24,147	24,080	24,080
VIII	REVDR	Residential Electric Vehicle (DR)	0	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	REVEE	Residential Electric Vehicle (EE)	150	301	523	661	675	680	682	682	680	632	531	381	159	21	7	0
VIII	RHRF	Residential Home Retrofit	6,619	12,156	18,062	21,255	21,711	21,881	21,942	21,942	21,942	21,961	21,859	21,859	21,941	22,042	21,935	21,934
VIII	RHVC	Residential Low-Income HVAC HB 2789	5,487	7,051	7,026	7,026	7,026	6,996	6,675	6,359	6,359	6,362	6,336	4,911	1,973	451	438	438
VIII	RKTS	Residential EE Kits	5,763	8,066	10,324	10,899	9,637	8,494	6,238	3,965	1,680	467	237	131	131	119	77	77
VIII	RMFP	Residential Multifamily Program	687	1,142	1,588	1,820	1,862	1,876	1,881	1,881	1,881	1,882	1,875	1,875	1,881	1,888	1,881	1,641
VIII	RMHP	Residential Manufactured Housing Program	727	1,232	1,728	1,980	2,024	2,038	2,044	2,044	2,044	2,044	2,038	2,038	2,044	1,801	1,315	815
VIII	RNCR	Residential New Construction	13,828	22,314	30,944	35,256	36,068	36,362	36,433	36,433	36,433	36,435	36,359	36,359	36,433	36,509	36,433	36,433
VIII	RTDR	Residential Smart Thermostat (DR)	648	869	1,058	1,142	1,165	1,182	1,195	1,208	1,220	1,231	1,243	1,254	1,264	1,277	1,291	1,305
VIII	RTEB	Residential Smart Thermostat Program (Behavioral)	1,551	1,197	1,043	543	122	66	0	0	0	0	0	0	0	0	0	0
VIII	RTEE	Residential Smart Thermostat (EE)	4,352	6,549	8,918	10,377	10,577	10,556	9,700	8,359	6,315	4,162	1,763	307	107	0	0	0
VIII	SBI2	Non Residential Small Business Improvement Enhanced Program	10,884	16,352	21,748	24,496	24,969	25,156	25,220	25,220	25,208	25,175	25,125	25,125	25,175	24,471	19,940	14,518
IX	CAGR	Non-Residential Agricultural	2,932	4,832	6,673	8,535	9,424	9,423	9,424	9,424	9,424	9,488	9,376	9,376	9,424	9,471	8,390	6,472
IX	CBAS	Non-Res Building Automation Program	6,418	10,769	14,992	19,265	21,581	21,825	21,791	21,791	21,791	21,946	21,717	21,717	21,791	21,911	21,791	21,791
IX	CBOT	Non-Res Building Optimization	7,825	13,130	18,278	23,489	26,313	26,610	23,922	18,711	13,500	8,355	3,077	256	0	0	0	0
IX	CENG	Non-Res Engagement Program	6,650	11,158	15,534	19,962	22,374	22,638	20,353	15,925	11,496	7,124	2,638	229	0	0	0	0
IX	CNR2	Non-Residential Enhanced Prescriptive Program	26,398	43,544	60,494	77,539	86,141	77,674	60,502	43,457	26,413	9,415	766	0	0	0	0	0
IX	EAL4	Enhancement of Residential Income and Age Qualifying	865	1,443	2,018	2,594	2,912	2,945	2,941	2,941	2,941	2,947	2,653	2,076	1,500	925	347	29
IX	EALS	Low-Income HVAC HB 2789 (Solar Component)	3,285	5,446	6,416	6,416	6,416	6,416	6,416	6,416	6,416	6,434	6,408	6,408	6,416	6,438	6,416	6,416
IX	RSMH	Residential Smart Home Program	11,800	23,232	37,775	55,551	64,578	65,189	65,131	65,131	65,131	65,311	61,470	53,286	41,943	27,430	9,580	553
IX	RVAU	Residential Virtual Audit Program	27,404	42,326	55,474	68,011	74,437	75,138	75,096	75,096	75,096	75,352	75,011	75,011	75,096	75,285	75,096	75,096
IX	RWDR	Residential Water Savings (DR) Program	9	24	54	105	163	179	181	183	185	187	188	190	192	194	196	198
IX	RWEE	Residential Water Savings (EE) Program	4,396	10,411	20,414	34,988	42,716	43,143	43,086	43,086	43,086	43,172	43,064	41,901	38,692	32,745	22,669	8,096
X	CDAC	Non Res Data Center and Server Rooms	365	1,419	3,514	6,704	10,291	11,980	11,954	11,954	11,954	12,000	11,939	11,939	11,954	11,629	10,539	8,440
X	CHA4	Non-Residential Hotel and Lodging	6,274	20,053	36,871	55,544	72,776	80,232	79,932	79,932	79,932	80,232	79,932	79,932	73,656	60,136	43,059	24,385
X	CHT4	Non-Residential Health Care	7,428	23,745	43,684	65,833	86,255	95,083	94,731	94,731	94,731	95,083	94,731	94,731	94,731	95,038	87,300	71,035
X	CIAQ	Non Res IAQ Healthcare and Rental Property Owners	10	29	48	67	87	96	96	96	96	96	96	96	96	96	87	67
X	CLT4	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	38,801	109,756	180,233	250,950	321,661	353,632	353,423	353,423	353,423	354,711	353,021	314,220	243,930	173,750	102,473	31,762
X	CSBB	Small Business Behavioral	10,137	17,283	15,870	14,600	13,432	5,682	0	0	0	0	0	0	0	0	0	0
X	REE2	Residential Efficient Products Marketplace Program	144,347	193,525	199,834	206,891	214,089	216,698	217,410	217,410	217,410	217,385	216,689	216,689	217,410	218,107	217,410	217,410
X	RIAQ	Residential IAQ Enhancements	18	51	84	118	151	167	166	166	166	167	166	166	166	167	166	166
X	RLMI	Residential IAQ Home Energy Report	757	1,288	1,288	1,288	1,288	531	0	0	0	0	0	0	0	0	0	0
X	VOPT	Voltage Optimization	21,074	91,128	186,646	282,346	378,048	474,533	569,086	627,310	641,723	646,606	647,842	651,195	655,145	660,569	661,856	665,212
	VOPT NONJU	VOPT for Non-Jurisdictional class	3,161	13,669	27,997	42,352	56,707	71,180	85,363	94,096	96,258	96,991	97,176	97,679	98,272	99,085	99,278	99,782
		Total	**1,403,597**	**1,758,647**	**2,021,577**	**2,291,073**	**2,503,799**	**2,554,968**	**2,588,174**	**2,608,861**	**2,549,796**	**2,475,710**	**2,404,144**	**2,266,036**	**2,093,353**	**1,919,431**	**1,699,463**	**1,467,512**

Appendix 6E - Approved Programs Penetrations
(System Level)

Phase	Acronym	Programs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
II	DG	Commercial Distributed Generation Program	8	9	10	11	12	12	12	12	12	12	12	12	12	12	12	13
VII	CHV3	Non-Residential Heating and Cooling Efficiency Program	1,400	1,463	1,527	1,592	1,658	1,658	1,658	1,658	1,658	1,658	1,658	1,658	1,658	1,658	958	258
VII	CLT3	Non-Residential Lighting Systems & Controls Program	366	366	366	366	366	366	366	366	366	366	0	0	0	0	0	0
VII	CSW2	Non-Residential Window Film Program	267,900	279,984	292,310	304,883	317,707	317,707	317,707	317,707	317,707	183,757	49,807	37,723	25,397	12,824	0	0
VII	CTSM	Non-Residential Small Manufacturing Program	140	146	152	158	164	164	164	164	164	164	164	94	24	18	12	6
VII	CTSO	Non-Residential Office Program	168	176	184	234	326	326	242	158	150	142	92	0	0	0	0	0
VII	RAR2	Residential Appliance Recycling Program (v2)	19,000	19,865	20,747	21,647	22,565	22,565	22,565	13,065	3,565	2,700	1,818	918	0	0	0	0
VII	RCEB	Residential Customer Engagement Program	258,300	240,500	223,900	287,500	277,400	0	0	0	0	0	0	0	0	0	0	0
VII	RTHO	Home Energy Assessment	68,456	71,353	74,308	77,322	80,396	80,396	80,396	80,396	80,396	80,396	80,396	46,348	11,940	9,043	6,088	3,074
VIII	CEEP	Non-Residential EE Products	564	846	1,128	1,156	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	903
VIII	CHVLI	Non-residential Heating & Cooling HB 2789	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	9
VIII	CMFP	Commercial Multifamily Program	3,242	4,863	6,484	6,634	6,787	6,787	6,787	6,787	5,166	3,545	1,924	303	153	0	0	0
VIII	CNCR	Non-Residential New Construction	150	300	450	459	468	468	468	468	468	468	468	468	468	468	468	468
VIII	REVDR	Residential Electric Vehicle (DR)	477	954	1,693	2,447	3,216	3,253	3,288	3,321	3,354	3,386	3,416	3,447	3,477	3,516	3,556	3,596
VIII	REVEE	Residential Electric Vehicle (EE)	1,778	3,385	5,746	5,871	5,999	5,999	5,999	5,999	5,999	5,296	4,221	2,614	253	128	0	0
VIII	RHRF	Residential Home Retrofit	4,500	7,500	10,500	10,728	10,961	10,961	10,961	10,961	10,961	10,961	10,961	10,961	10,961	10,961	10,961	10,961
VIII	RHVC	Residential Low-Income HVAC HB 2789	17,582	17,582	17,582	17,582	17,582	17,582	17,582	17,582	17,582	17,582	17,582	8,791	0	0	0	0
VIII	RKTS	Residential EE Kits	60,000	90,000	120,000	123,000	126,060	96,060	66,060	36,060	6,060	3,060	0	0	0	0	0	0
VIII	RMFP	Residential Multifamily Program	26,316	39,474	52,632	53,854	55,100	55,100	55,100	55,100	55,100	55,100	55,100	55,100	55,100	55,100	55,100	41,942
VIII	RMHP	Residential Manufactured Housing Program	4,324	6,580	8,836	9,032	9,231	9,231	9,231	9,231	9,231	9,231	9,231	9,231	9,231	7,163	4,907	2,651
VIII	RNCR	Residential New Construction	8,848	13,741	18,634	19,087	19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549
VIII	RTDR	Residential Smart Thermostat (DR)	29,836	38,473	45,348	46,255	47,180	47,723	48,237	48,732	49,208	49,668	50,115	50,552	50,983	51,543	52,110	52,683
VIII	RTEB	Residential Smart Thermostat Program (Behavioral)	9,163	8,637	6,875	907	925	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEE	Residential Smart Thermostat (EE)	8,729	13,464	18,958	19,382	19,814	19,814	19,814	15,577	11,085	6,350	856	432	0	0	0	0
VIII	SBI2	Non Residential Small Business Improvement Enhanced Program	1,350	2,025	2,700	2,768	2,837	2,837	2,837	2,837	2,837	2,837	2,837	2,837	2,837	2,837	2,162	1,487
IX	CAGR	Non-Residential Agricultural	293	435	577	719	719	719	719	719	719	719	719	719	719	719	568	426
IX	CBAS	Non-Res Building Automation Program	60	90	120	150	153	153	153	153	153	153	153	153	153	153	153	153
IX	CBOT	Non-Res Building Optimization	60	90	120	150	153	153	123	93	63	33	3	0	0	0	0	0
IX	CENG	Non-Res Engagement Program	114	171	228	285	291	291	234	177	120	63	6	0	0	0	0	0
IX	CNR2	Non-Residential Enhanced Prescriptive Program	1,200	1,800	2,400	3,000	3,060	2,460	1,860	1,260	660	60	0	0	0	0	0	0
IX	EAL4	Enhancement of Residential Income and Age Qualifying	20,690	31,035	41,380	51,725	52,760	52,760	52,760	52,760	52,760	52,760	42,415	32,070	21,725	11,380	1,035	0
IX	EALS	Low-Income HVAC HB 2789 (Solar Component)	1,110	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665
IX	RSMH	Residential Smart Home Program	12,835	23,103	35,939	51,342	52,369	52,369	52,369	52,369	52,369	52,369	47,235	39,534	29,266	16,430	1,027	0
IX	RVAU	Residential Virtual Audit Program	110,000	155,000	195,000	235,000	239,700	239,700	239,700	239,700	239,700	239,700	239,700	239,700	239,700	239,700	239,700	239,700
IX	RWDR	Residential Water Savings (DR) Program	2,660	7,074	15,422	29,218	43,290	43,786	44,258	44,710	45,147	45,572	45,989	46,399	46,806	47,333	47,866	48,405
IX	RWEE	Residential Water Savings (EE) Program	3,000	6,600	12,400	20,400	20,808	20,808	20,808	20,808	20,808	20,808	20,808	19,808	17,808	14,208	8,408	408
X	CDAC	Non Res Data Center and Server Rooms	4	12	28	49	70	70	70	70	70	70	70	70	70	66	58	42
X	CHA4	Non-Residential Hotel and Lodging	163	380	632	901	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118	955	738	486	217
X	CHT4	Non-Residential Health Care	193	450	749	1,068	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,132	875
X	CIAQ	Non Res IAQ Healthcare and Rental Property Owners	200	400	600	800	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	800	600
X	CLT4	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	970	1,940	2,910	3,880	4,850	4,850	4,850	4,850	4,850	4,850	4,850	3,880	2,910	1,940	970	0
X	CSBB	Small Business Behavioral	45,000	41,400	38,088	35,041	32,238	0	0	0	0	0	0	0	0	0	0	0
X	REE2	Residential Efficient Products Marketplace Program	9,842,300	10,198,339	10,561,499	10,931,922	11,309,753	11,309,753	11,309,753	11,309,753	11,309,753	11,309,753	11,309,753	11,309,753	11,309,753	11,309,753	11,309,753	11,309,753
X	RIAQ	Residential IAQ Enhancements	400	800	1,200	1,600	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
X	RLMI	Residential IAQ Home Energy Report	3,500	3,500	3,500	3,500	3,500	0	0	0	0	0	0	0	0	0	0	0
X	VOPT	Voltage Optimization (DVI)	62	216	370	524	678	832	985	1,030	1,035	1,041	1,046	1,051	1,057	1,062	1,068	1,073
		Total	**10,837,429**	**11,336,204**	**11,845,915**	**12,385,832**	**12,799,006**	**12,455,572**	**12,425,976**	**12,382,493**	**12,337,136**	**12,192,489**	**12,031,265**	**11,952,486**	**11,870,158**	**11,825,496**	**11,773,775**	**11,742,916**

Appendix 6F – Description of Proposed DSM Programs

<u>Residential Peak Time Rebate Program</u>
Target Class: Residential
VA Program Type: Energy Efficiency/Demand Response
NC Program Type: Energy Efficiency/Demand Response

Program Description:
This Program would enable residential customers to reduce their energy usage consumption during peak time periods as called upon by the Company. During peak time rebate event days, proposed program design will alert customers with text messaging, emails or outbound telemarketing voicemail, as well as by utilizing the Company's dominionenergy.com website with banner announcements informing participants an event is in progress

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.

<u>Non-Residential Custom Program</u>
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
This Program would provide qualifying non-residential customers, with a focus on larger facilities with demand greater than 300 kW, with the technical support and incentives needed to pursue non-standard, more complex energy efficiency projects. Qualifying non-residential customers develop tailored projects that best meet their unique facility and organizational goals while achieving savings from a diverse mix of measures

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 this program is 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.

<u>Residential Electric Vehicle (EV) Pilot Program</u>
Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency

Program Description:
The proposed program pilot would run in parallel with the current Electric Vehicle Demand Response Program. Instead of communicating with the electric vehicle charger, the proposed pilot program

would allow for integration with newer technology onboard vehicle telematics to capture charging data and control the charging rate during load curtailment events dispatched by the Company.

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.

<u>Residential Income and Age Qualifying Home Improvement Program Bundle</u>

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
The proposed bundled version of the Residential Income and Age Qualifying Home Improvement Program combines the Company's existing HB 2789 HVAC Program measures in addition to the Phase IX and X low-income program measures while adding several new program measures and creating a bundled income qualifying program that would provide income and age qualifying residential customers with in-home energy assessments and installation of select energy-saving measures. Energy assessments and installations will be conducted by qualified, local weatherization service providers ("WSP") who currently offer weatherization related services through the Virginia Department of Housing and Community Development and have been approved by the Income and Age Qualifying Program to complete assessments and install the selected energy-saving products.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

<u>Non-residential Income and Age Qualifying Home Improvement Program Bundle</u>

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
Program would offer installation of select energy-saving measures to be installed in properties that house low-income and aging residents, but the electric bill is paid by the property, rather than the individual resident. This would include housing authority and master metered properties, assisted living residences, and nursing homes.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

Appendix 6F – Description of Proposed DSM Programs

Non-residential Prescriptive Program Bundle

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
The proposed program design would offer a more comprehensive program bundle that would incorporate the Company's expiring DSM Phase VII Non-residential Heating and Cooling Efficiency, Non-residential Manufacturing and Non-residential Window Film Programs into the overarching DSM Phase IX Non-residential Enhanced Prescriptive Program offering. The consolidation of various program measures into a more enhanced version of the Phase IX Non-residential Prescriptive Program would allow the Company to consolidate programs and offer qualifying non-residential customers the ease of implementing a wide variety of energy efficiency measures.

This Program would provide qualifying non-residential customers with incentives for the installation of refrigeration, commercial kitchen equipment, HVAC improvements, window film installation and maintenance and installation of other program specific, energy efficiency measures.

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 this program is 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.

Residential Retrofit Program Bundle

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency

Program Description:
The proposed program re-design incorporates key program measures from the Company's Phase VII Residential Home Energy Assessment Program and measures from the existing Home Retrofit Program.

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 this program is 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 6G - Proposed Programs Non-Coincidental Peak Savings
(kW) (System Level)

Phase	Acronym	Programs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
XI	CLIB	Non-Residential Income and Age Qualifying Bundle	0	13	28	44	64	84	101	101	101	101	101	101	101	101	101	98
XI	CNR3	Non-Residential Enhanced Prescriptive Program	6,963	11,440	16,082	20,724	22,563	22,563	22,563	22,563	20,170	16,068	11,748	7,343	3,557	0	0	0
XI	CST4	Non-Residential Custom	0	8,929	24,424	42,082	61,408	82,743	84,535	84,535	84,535	84,535	84,535	84,535	84,535	84,535	84,535	84,535
XI	RCEB2	Residential Customer Engagement Program (Extension)	0	18,686	32,186	33,910	31,197	28,701	15,037	0	0	0	0	0	0	0	0	0
XI	REEC3	Residential Efficient Products Marketplace Program (Extensior	0	2,269	5,844	9,815	14,096	18,902	20,394	20,394	20,394	20,394	20,394	20,394	20,394	18,342	14,618	10,579
XI	RHR2	Residential Enhanced Home Retrofit	2,847	10,895	18,942	20,045	20,045	20,045	20,045	20,045	20,045	20,045	20,045	20,045	20,045	20,045	20,045	20,045
XI	RLIB	Residential Income and Age Qualifying Bundle	0	1,972	3,944	6,579	9,616	12,652	15,183	15,183	15,183	15,183	15,183	15,183	15,183	14,677	11,640	8,603
XI	RPIL	Residential Telematics Vehicle Charger Pilot	0	204	555	906	964	0	0	0	0	0	0	0	0	0	0	0
XI	RPTR	Residential Peak Time Rebate	0	12,590	49,912	98,474	147,037	195,600	89,931	0	0	0	0	0	0	0	0	0
		Total	**9,810**	**66,998**	**151,917**	**232,579**	**306,991**	**381,290**	**267,789**	**162,821**	**160,428**	**156,326**	**152,007**	**147,601**	**143,815**	**137,700**	**130,940**	**123,861**

Appendix 6H - Proposed Programs Coincidental Peak Savings (kW) (System Level)

Phase	Acronym	Programs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
XI	CLIB	Non-Residential Income and Age Qualifying Bundle	0	3	9	14	19	25	27	27	27	27	27	27	27	27	27	24
XI	CNR3	Non-Residential Enhanced Prescriptive Program	6,475	10,961	15,732	20,503	22,491	22,491	22,491	22,491	20,105	16,016	11,529	6,759	1,988	0	0	0
XI	CST4	Non-Residential Custom	0	676	2,289	4,344	6,600	9,082	10,159	10,159	10,159	10,159	10,159	10,159	10,159	10,159	10,159	10,159
XI	RCEB2	Residential Customer Engagement Program (Extension)	0	15,670	31,513	33,209	30,553	28,108	11,302	0	0	0	0	0	0	0	0	0
XI	REEC3	Residential Efficient Products Marketplace Program (Extension)	0	1,768	4,976	8,456	12,145	16,003	17,570	17,570	17,570	17,570	17,614	17,570	17,570	15,802	12,594	9,114
XI	RHR2	Residential Enhanced Home Retrofit	1,030	3,529	7,295	8,864	8,864	8,864	8,864	8,864	8,864	8,864	8,864	8,864	8,864	8,864	8,864	8,864
XI	RLIB	Residential Income and Age Qualifying Bundle	0	303	822	1,341	1,953	2,499	2,595	2,595	2,595	2,595	2,726	2,726	2,595	2,292	1,773	1,317
XI	RPIL	Residential Telematics Vehicle Charger Pilot	0	204	555	906	438	0	0	0	0	0	0	0	0	0	0	0
XI	RPTR	Residential Peak Time Rebate	0	12,590	49,912	98,474	147,037	195,600	89,931	0	0	0	0	0	0	0	0	0
		Total	**7,505**	**45,705**	**113,102**	**176,111**	**230,100**	**282,671**	**162,939**	**61,706**	**59,320**	**55,231**	**50,918**	**46,104**	**41,203**	**37,144**	**33,417**	**29,478**

Appendix 6I - Proposed Programs Energy Savings
(MWh) (System Level)

Phase	Acronym	Programs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
XI	CLIB	Non-Residential Income and Age Qualifying Bundle	0	11	32	54	75	97	107	107	107	107	107	107	107	107	107	96
XI	CNR3	Non-Residential Enhanced Prescriptive Program	30,335	51,905	74,686	97,589	107,931	108,009	107,931	107,931	97,179	77,830	56,067	33,211	10,364	0	0	0
XI	CST4	Non-Residential Custom	0	5,867	21,324	41,616	63,905	88,458	101,029	101,029	101,029	101,747	100,682	100,682	101,029	101,585	101,029	101,029
XI	RCEB2	Residential Customer Engagement Program (Extension)	0	26,974	56,505	60,112	55,301	51,009	21,779	0	0	0	0	0	0	0	0	0
XI	REEC3	Residential Efficient Products Marketplace Program (Extension)	0	5,510	16,425	28,282	40,866	54,073	60,105	60,105	60,105	60,278	60,098	60,098	60,105	54,785	43,683	31,825
XI	RHR2	Residential Enhanced Home Retrofit	4,771	16,166	33,946	41,846	41,846	41,847	41,846	41,846	41,846	41,851	41,846	41,846	41,846	41,846	41,846	41,846
XI	RLIB	Residential Income and Age Qualifying Bundle	0	787	2,328	3,869	5,410	6,951	7,707	7,707	7,707	7,722	7,703	7,703	7,707	6,929	5,379	3,838
XI	RPIL	Residential Telematics Vehicle Charger Pilot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
XI	RPTR	Residential Peak Time Rebate	0	6	28	57	86	115	63	0	0	0	0	0	0	0	0	0
		Total	**35,106**	**107,227**	**205,273**	**273,424**	**315,420**	**350,559**	**340,566**	**318,725**	**307,973**	**289,535**	**266,503**	**243,648**	**221,158**	**205,251**	**192,044**	**178,634**

Appendix 6J - Proposed Programs Penetrations
(System Level)

Phase	Acronym	Programs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
XI	CLIB	Non-Residential Income and Age Qualifying Bundle	0	210	420	630	840	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	840
XI	CNR3	Non-Residential Enhanced Prescriptive Program	1,200	1,900	2,600	3,300	3,300	3,300	3,300	3,300	2,700	2,100	1,400	700	0	0	0	0
XI	CST4	Non-Residential Custom	0	52	139	235	340	456	456	456	456	456	456	456	456	456	456	456
XI	RCEB2	Residential Customer Engagement Program (Extension)	0	265,431	344,197	316,661	291,328	268,022	0	0	0	0	0	0	0	0	0	0
XI	REEC3	Residential Efficient Products Marketplace Program (Extension)	0	206,049	432,703	676,355	932,192	1,194,427	1,194,427	1,194,427	1,194,427	1,194,427	1,194,427	1,194,427	1,194,427	988,378	761,724	518,072
XI	RHR2	Residential Enhanced Home Retrofit	4,599	17,599	30,599	30,599	30,599	30,599	30,599	30,599	30,599	30,599	30,599	30,599	30,599	30,599	30,599	30,599
XI	RLIB	Residential Income and Age Qualifying Bundle	0	14,154	28,308	42,462	56,616	70,770	70,770	70,770	70,770	70,770	70,770	70,770	70,770	56,616	42,462	28,308
XI	RPIL	Residential Telematics Vehicle Charger Pilot	0	333	667	1,000	0	0	0	0	0	0	0	0	0	0	0	0
XI	RPTR	Residential Peak Time Rebate	0	25,000	81,250	137,500	193,750	250,000	0	0	0	0	0	0	0	0	0	0
		Total	**5,799**	**530,728**	**920,883**	**1,208,742**	**1,508,965**	**1,818,624**	**1,300,602**	**1,300,602**	**1,300,002**	**1,299,402**	**1,298,702**	**1,298,002**	**1,297,302**	**1,077,099**	**836,291**	**578,275**

Appendix 6K - Future Undesignated EE Coincidental Peak Savings
(kW) (System Level)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Generic Undesignated EE Programs	80,232	142,294	307,510	266,917	237,749	219,728	220,686	160,996	222,261	243,046	272,788	289,232	320,264	335,935	383,606	456,577
Total	**80,232**	**142,294**	**307,510**	**266,917**	**237,749**	**219,728**	**220,686**	**160,996**	**222,261**	**243,046**	**272,788**	**289,232**	**320,264**	**335,935**	**383,606**	**456,577**

Appendix 6L - Future Undesignated EE Energy Savings
(MWh) (System Level)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Generic Undesignated EE Programs	382,191	962,357	1,619,256	1,373,414	1,181,595	1,141,197	1,117,708	1,102,189	1,159,516	1,230,456	1,297,421	1,427,823	1,589,830	1,754,876	1,963,100	2,240,409
Total	**382,191**	**962,357**	**1,619,256**	**1,373,414**	**1,181,595**	**1,141,197**	**1,117,708**	**1,102,189**	**1,159,516**	**1,230,456**	**1,297,421**	**1,427,823**	**1,589,830**	**1,754,876**	**1,963,100**	**2,240,409**

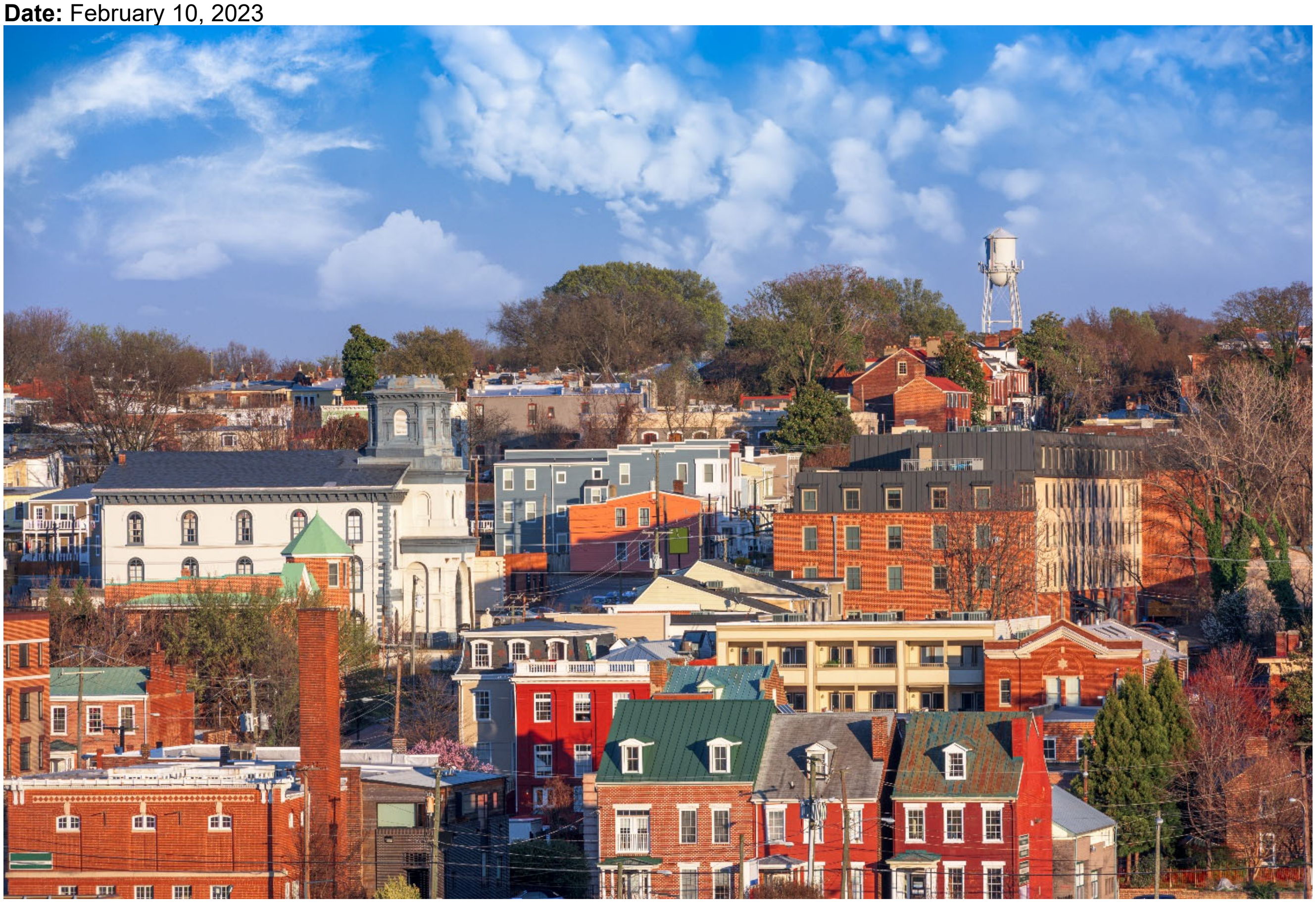
Appendix 6M - Rejected DSM Programs

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
Residential Home Energy Assessment
Non-Residential Re-commissioning Program
Non-Residential Compressed Air System Program
Non-Residential Strategic Energy Management
Non-Residential Agricultural EE
Non-Residential Telecommunication Optimization
Residential Bring Your Own Device
Non-Residential Battery Storage
Residential Battery Storage
Non-Residential DR Outreach
Residential Water Heating

National Comparison Analyses

Dominion Energy

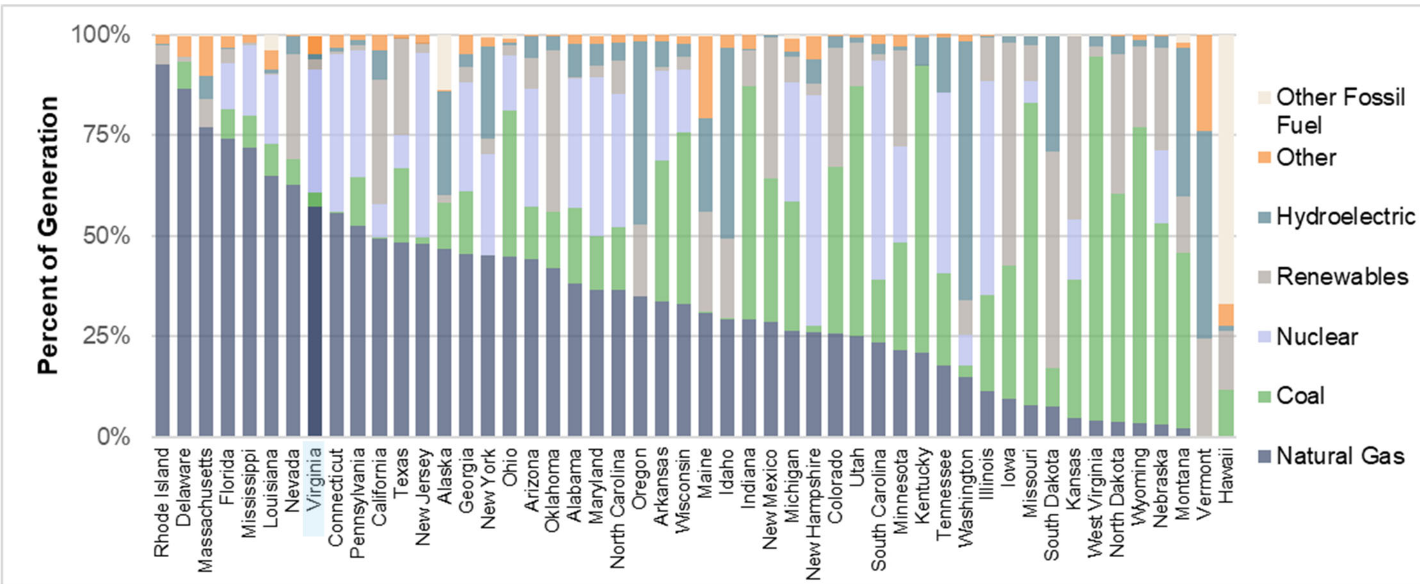
Date: February 10, 2023



1 FUEL SOURCE FOR GENERATION

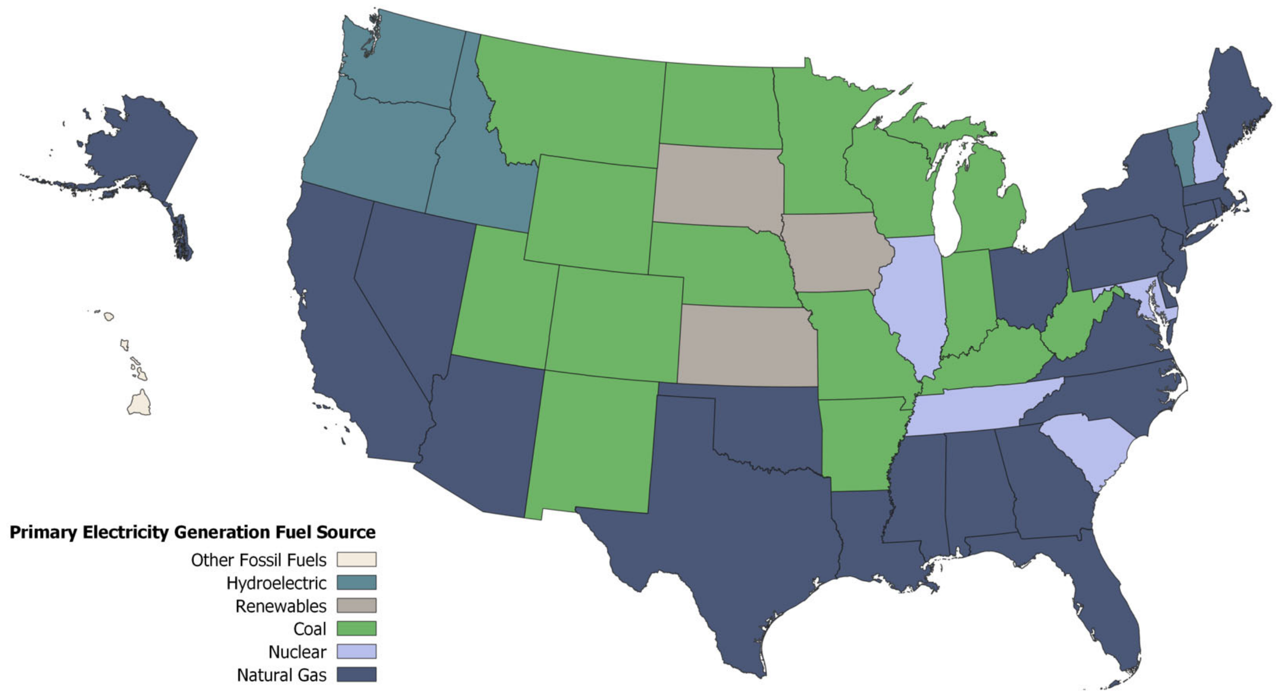
The generation mix of a state can be a significant determinant of its electricity cost. Figure 1 and Figure 2 compare Virginia's generation mix with the rest of the country. Virginia's primary source of electricity generation is natural gas, followed by nuclear. This generation mix is similar to Connecticut, Pennsylvania, Louisiana, Florida, and Mississippi. In each state, over 80% of the generation mix is comprised of natural gas and nuclear—with natural gas accounting for over 50%.

Figure 1. Electricity generation mix, as fraction of total.[1]



[1] U.S Energy Information Administration. EIA-923 Power Plant Operations Report. Released 10.14.2022. https://www.eia.gov/electricity/data/state/

Figure 2. Map of primary generation fuel source in each state.[2]



2 OTHER METRICS

Variation in electricity bills between states depends in part on the prevalence of electric heating and cooling equipment, cooling and heating loads, and housing size.

Space heating represents a large proportion of many consumers' total energy use. The use of electricity for heating varies widely across regions. Among electrically heated homes, some types of equipment are more efficient than others. Table 1 shows the percentage of different fuels used for home heating in ten Census divisions. Virginia is part of the South Atlantic division that includes Delaware, Maryland, West Virginia, North Carolina, South Carolina, Georgia, Florida, and the District of Columbia. Table 2 shows the mix of different heating equipment by Census division. Table 3 shows the mix of different electric heating equipment by Census division. The South Atlantic division has a large fraction of homes heated by electricity compared to the more northern parts of the country. Of those South Atlantic customers who use electric heat, most use either electric central warm-air furnaces or electric heat pumps. The South Atlantic division also has a larger fraction of homes without heating equipment, as compared to the other regions. Relatively fewer customers in the South Atlantic use central warm-air furnaces for heat, and relatively more use heat pumps when compared to other areas.[3]

[2] U.S Energy Information Administration. EIA-923 Power Plant Operations Report. Released 10.14.2022. https://www.eia.gov/electricity/data/state/

[3] U.S. Department of Energy, Energy Information Administration. (2020). 2020 Residential Energy Consumption Survey (RECS). Retrieved from Housing characteristics tables, Tables HC6.7 and HC6.8: https://www.eia.gov/consumption/residential/data/2020/,

Table 1. Space heating equipment by fuel source by Census division[4].

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain North	Mountain South	Pacific
Natural gas	41%	58%	68%	59%	24%	29%	34%	68%	42%	49%
Electricity	17%	23%	22%	28%	61%	66%	58%	25%	45%	34%
Fuel oil/kerosene	33%	13%	1%	1%	2%	N/A	N/A	N/A	N/A	0%
Propane	6%	4%	7%	10%	2%	4%	2%	4%	3%	2%
Wood	3%	2%	2%	2%	1%	2%	1%	3%	3%	2%
Some other fuel[3]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Do not use heating equipment	N/A	1%	1%	N/A	10%	N/A	4%	N/A	7%	12%

4 U.S. Department of Energy, Energy Information Administration. (2020). 2020 Residential Energy Consumption Survey (RECS). Retrieved from Housing characteristics tables, Tables HC6.7 and HC6.8: https://www.eia.gov/consumption/residential/data/2020/,

Table 2. Saturation of heating equipment types by Census division[5].

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Moun-tain North	Moun-tain South	Pacific
Central warm-air furnace	54%	50%	79%	78%	45%	50%	58%	77%	58%	54%
Heat pump	2%	5%	3%	6%	32%	35%	21%	2%	20%	6%
Steam or hot water system	26%	28%	8%	7%	2%	1%	N/A	7%	2%	2%
Ductless heat pump (mini-split)	2%	1%	N/A	N/A	1%	1%	1%	N/A	1%	2%
Built-in electric units	10%	10%	7%	6%	4%	4%	6%	8%	4%	10%
Built-in oil or gas room heater	3%	2%	1%	2%	1%	3%	2%	2%	3%	6%
Portable electric heaters	N/A	1%	N/A	N/A	2%	4%	6%	1%	2%	6%
Heating stove burning wood	3%	2%	1%	1%	1%	1%	1%	3%	3%	2%
Some other equipment	1%	N/A	N/A	N/A	1%	1%	1%	1%	N/A	0%
Does not use heating equipment	N/A	1%	1%	N/A	10%	N/A	4%	N/A	7%	12%

Table 3. Electric heating equipment mix[6].

		New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Moun-tain North	Moun-tain South	Pacific
Fraction of Homes Heated by Electricity		17%	23%	22%	28%	61%	66%	58%	25%	45%	34%
Fraction Electric-Heated Homes	Central warm-air furnace	16%	21%	46%	52%	34%	32%	42%	56%	39%	31%
	Heat pump	11%	21%	16%	23%	53%	54%	35%	7%	44%	18%
	Ductless heat pump (mini-split)	9%	5%	N/A	N/A	2%	1%	1%	N/A	3%	5%

[5] U.S. Department of Energy, Energy Information Administration. (2020). 2020 Residential Energy Consumption Survey (RECS). Retrieved from Housing characteristics tables, Tables HC6.7 and HC6.8: https://www.eia.gov/consumption/residential/data/2020/,

[6] U.S. Department of Energy, Energy Information Administration. (2020). 2020 Residential Energy Consumption Survey (RECS). Retrieved from Housing characteristics tables, Tables HC6.7 and HC6.8: https://www.eia.gov/consumption/residential/data/2020/,

		New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Moun-tain North	Moun-tain South	Pacific
	Built-in electric units	57%	42%	32%	20%	6%	7%	10%	33%	9%	28%
	Portable electric heaters	N/A	5%	N/A	N/A	4%	6%	10%	4%	5%	17%

Climate is also a key driver of customers' electricity bills. Heating degree days ("HDD") and cooling degree days ("CDD") are often used as proxies for cooling and heating load. It also measures how much the daily temperature diverges from a base temperature (below 65° Fahrenheit for heating and above the 65° Fahrenheit for cooling). Virginia's annual cooling and heating degree days in 2021 were near the US average. In 2021, Virginia had 1,608 CDD[7] compared to the national average of 1,489 CDD[8] and 3,370 HDD[9] compared to the national average of 3,938 HDD.[10]

However, the number of HDD and CDD vary widely across US regions. See Figure 3 and Figure 4. We added Virginia's 2021 CDD and HDD to the maps for comparison.

[7] Energy Star Portfolio Manager. Degree Days Calculator. https://portfoliomanager.energystar.gov/pm/degreeDaysCalculator
[8] U.S. Energy Information Administration. Monthly Energy Review. https://www.eia.gov/totalenergy/data/monthly/
[9] Energy Star Portfolio Manager. Degree Days Calculator. https://portfoliomanager.energystar.gov/pm/degreeDaysCalculator
10 [10] U.S. Energy Information Administration. Monthly Energy Review. https://www.eia.gov/totalenergy/data/monthly/

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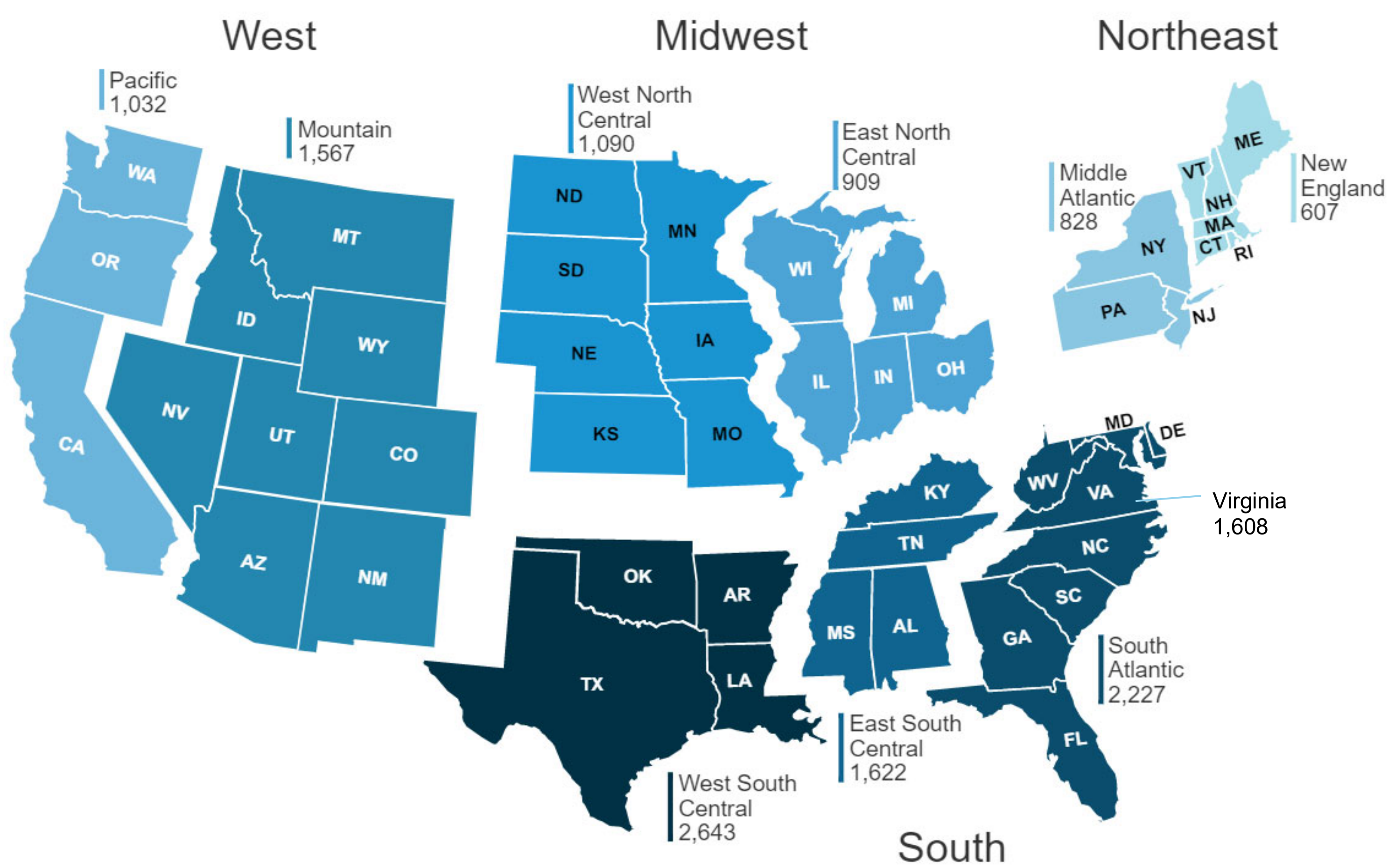
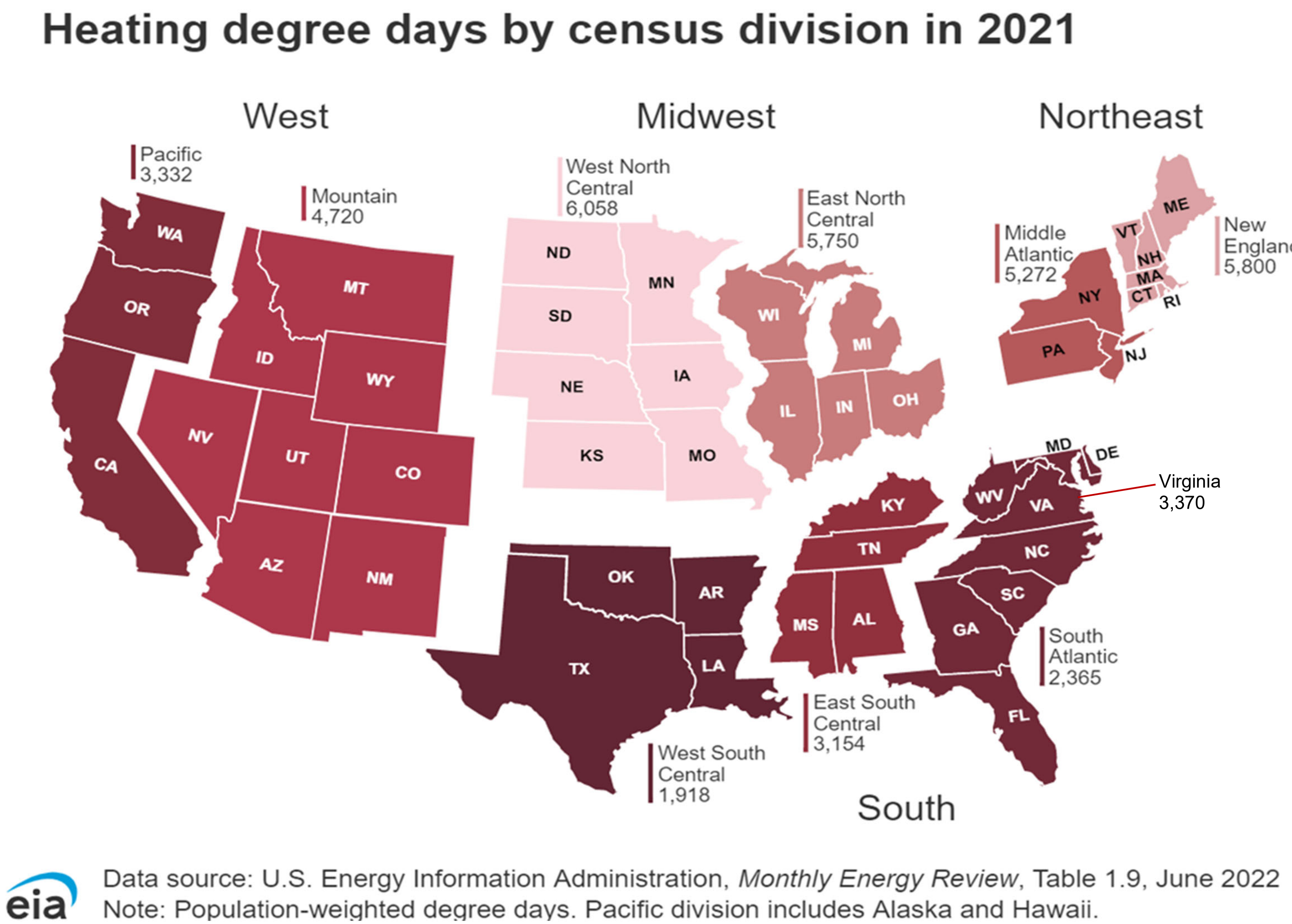
Figure 3. Cooling degree days by Census division in 2021.

Cooling degree days by census division in 2021



eia Data source: U.S. Energy Information Administration, *Monthly Energy Review*, Table 1.10, June 2022
Note: Population-weighted degree days. Pacific division includes Alaska and Hawaii.

Figure 4. heating degree days by Census division in 2021.[11]



[11] U.S. Department of Energy, Energy Information Administration (EIA). (n.d.). Units and calculators explained. Retrieved from Degree days: https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php

Housing size also affects electricity bills – larger houses require more energy to cool, heat, light, etc. Table 4 shows how housing average square footage varies across the U.S. The South Atlantic division's average home size falls generally in the middle of other census divisions. The South Atlantic heats fewer square feet/house and cools more square feet/house in comparison to most other parts of the country.[12]

Table 4. Average home size[13]

	Average Square Footage per Housing Unit		
	Total	**Heated**	**Cooled**
All homes	**2,008**	**1,754**	**1,375**
New England	2,186	1,861	783
Middle Atlantic	2,055	1,765	1,100
East North Central	2,250	2,051	1,563
West North Central	2,338	2,024	1,758
South Atlantic	1,999	1,669	1,615
East South Central	1,870	1,625	1,393
West South Central	1,873	1,725	1,592
Mountain North	2,171	2,037	1,294
Mountain South	1,844	1,755	1,427
Pacific	1,689	1,405	947

12 U.S. Department of Energy, Energy Information Administration (EIA). (2015). Residential Energy Consumption Survey (RECS). Retrieved from Square footage (housing unit size), Table HC10.9: https://www.eia.gov/consumption/residential/data/2015/#squarefootage

13 U.S. Department of Energy, Energy Information Administration (EIA). (2015). Residential Energy Consumption Survey (RECS). Retrieved from Square footage (housing unit size), Table HC10.9: https://www.eia.gov/consumption/residential/data/2015/#squarefootage

About DNV

DNV is a global quality assurance and risk management company. Driven by our purpose of safeguarding life, property and the environment, we enable our customers to advance the safety and sustainability of their business. We provide classification, technical assurance, software and independent expert advisory services to the maritime, oil & gas, power and renewables industries. We also provide certification, supply chain and data management services to customers across a wide range of industries. Operating in more than 100 countries, our experts are dedicated to helping customers make the world safer, smarter and greener.

Appendix 6O - DSM Program Projected Savings By 2028

Phase	Program	Projected MW Winter	Projected MW Summer	Projected GWh Savings	Program Status
I	Low Income Program	0.39	0.09	0.60	Inactive
II	Commercial Distributed Generation Program	0.00	0.00	0.76	Active
	Commercial Duct Testing & Sealing Program	27.17	30.84	75.54	Inactive
	Heat Pump Upgrade Program	6.90	3.50	11.96	Inactive
	Residential Duct Testing & Sealing Program	0.47	0.20	0.94	Inactive
III	Non-Residential Heating and Cooling Efficiency Program	20.23	12.70	35.09	Inactive
	Non-Residential Lighting Systems & Controls Program	6.20	0.19	4.72	Inactive
	Non-Residential Window Film	0.00	0.03	0.07	Inactive
IV	Income and Age Qualifying Home Improvement Program	2.63	1.61	10.80	Active
V	Residential Retail LED Lighting Program (NC only)	1.13	0.69	7.27	Inactive
	Small Business Improvement Program	10.19	14.08	54.13	Inactive
VI	Non-Residential Prescriptive Program	0.96	0.00	1.68	Active
VII	Home Energy Assessment	20.40	4.71	170.06	Active
	Non-Residential Heating and Cooling Efficiency Program	71.13	9.05	48.82	Active
	Non-Residential Lighting Systems & Controls Program	8.69	8.74	55.59	Active
	Non-Residential Office Program	0.00	0.00	6.48	Active
	Non-Residential Small Manufacturing Program	2.00	3.24	17.47	Active
	Non-Residential Window Film Program	0.00	0.42	1.38	Active
	Residential Appliance Recycling Program (v2)	1.08	1.83	12.02	Active
	Residential Customer Engagement Program	0.00	0.00	29.20	Active
	Residential Efficient Products Marketplace Program	27.79	16.06	187.32	Inactive
VIII	Commercial Multifamily Program	1.41	1.96	12.24	Active
	Non Residential Small Business Improvement Enhanced Program	3.74	5.30	25.16	Active
	Non-Residential EE Products	0.74	5.58	10.47	Active
	Non-Residential New Construction	7.25	6.42	24.08	Active
	Non-residential Heating & Cooling HB 2789	0.00	0.00	0.01	Active
	Residential EE Kits	1.50	0.65	8.49	Active
	Residential Electric Vehicle (DR)	0.00	1.51	0.00	Active
	Residential Electric Vehicle (EE)	0.03	0.01	0.68	Active
	Residential Home Retrofit	8.56	6.90	21.88	Active
	Residential Low-Income HVAC HB 2789	4.77	1.01	7.00	Active
	Residential Manufactured Housing Program	0.24	0.12	2.04	Active
	Residential Multifamily Program	0.45	0.19	1.88	Active
	Residential New Construction	3.95	16.65	36.36	Active
	Residential Smart Thermostat (DR)	0.00	68.17	1.18	Active
	Residential Smart Thermostat (EE)	9.72	0.00	10.56	Active
	Residential Smart Thermostat Program (Behavioral)	0.10	0.00	0.07	Active
IX	Enhancement of Residential Income and Age Qualifying	1.66	0.75	2.94	Active
	Low-Income HVAC HB 2789 (Solar Component)	0.05	3.08	6.42	Active
	Non-Res Building Automation Program	10.21	2.19	21.83	Active
	Non-Res Building Optimization	12.45	2.67	26.61	Active
	Non-Res Engagement Program	10.59	2.27	22.64	Active
	Non-Residential Agricultural	2.14	0.74	9.42	Active
	Non-Residential Enhanced Prescriptive Program	13.25	16.28	77.67	Active
	Residential Smart Home Program	3.86	15.26	65.19	Active
	Residential Virtual Audit Program	7.74	25.54	75.14	Active
	Residential Water Savings (DR) Program	0.00	22.67	0.18	Active
	Residential Water Savings (EE) Program	5.44	21.31	43.14	Active
X	Non Res Data Center and Server Rooms	1.84	1.12	11.98	Active
	Non Res IAQ Healthcare and Rental Property Owners	0.05	0.02	0.10	Active
	Non-Residential Health Care	18.42	37.24	95.08	Active
	Non-Residential Hotel and Lodging	15.93	30.00	80.23	Active
	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	69.19	77.45	353.63	Active
	Residential Efficient Products Marketplace Program	31.59	17.28	216.70	Active
	Residential IAQ Enhancements	0.03	0.01	0.17	Active
	Residential IAQ Home Energy Report	0.00	0.71	0.53	Active
	Small Business Behavioral	1.22	2.98	5.68	Active
	Voltage Optimization	79.64	104.50	474.53	Active
	VOPT for Non-Jurisdictional class	9.81	12.03	71.18	Active

Appendix 6P: Comparison of per MWh Costs of Selected Generation

Comparison of per MWh Costs of Selected Resource	COD*	Capacity Factor	Cost ($/MWh) no RECs	Cost ($/MWh) with RECs
Voltage Optimization	2021	N/A	$3	N/A
Non-Residential Lighting Systems & Controls Program	2022	N/A	$6	N/A
Residential Efficient Products Marketplace Program	2022	N/A	$6	N/A
Home Energy Assessment	2022	N/A	$9	N/A
Non-Residential Heating and Cooling Efficiency Program	2022	N/A	$11	N/A
Small Business Behavioral	2021	N/A	$22	N/A
Non-Residential Small Manufacturing Program	2022	N/A	$23	N/A
Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	2021	N/A	$23	N/A
Residential Home Retrofit	2022	N/A	$39	N/A
Residential Customer Engagement Program	2022	N/A	$42	N/A
Non-Residential Health Care	2021	N/A	$42	N/A
Non Res Data Center and Server Rooms	2021	N/A	$43	N/A
Non-Residential Hotel and Lodging	2021	N/A	$47	N/A
Residential New Construction	2022	N/A	$49	N/A
Residential Smart Thermostat (EE)	2022	N/A	$49	N/A
Solar - PPA	2027	N/A	$51	N/A
Residential Appliance Recycling Program (v2)	2022	N/A	$58	N/A
Non-Residential Small Business Improvement Enhanced Program	2022	N/A	$71	N/A
Solar - Tracker	2027	25%	$72	$63
3x1 CC Greenfield	2027	80%	$72	N/A
2x1 CC Greenfield	2027	80%	$76	N/A
Wind - On-Shore	2027	37%	$79	$69
Non-Residential EE Products	2022	N/A	$79	N/A
Wind - Off-Shore	2027	43%	$83	$73
1x1 CC Greenfield	2027	80%	$91	N/A
Non-Residential Office Program	2022	N/A	$115	N/A
Storage - PPA	2027	N/A	$115	N/A
Residential Electric Vehicle (EE)	2022	N/A	$121	N/A
Residential EE Kits	2022	N/A	$124	N/A
Non-Residential Window Film Program	2022	N/A	$144	N/A
Nuclear SMR	2027	92%	$152	N/A
CT	2027	15%	$171	N/A
Distributed Solar (3 MW)	2027	24%	$209	$200
CT (Aero)	2027	15%	$247	N/A
Battery Generic 4H (30 MW)	2027	15%	$275	N/A
Residential Smart Thermostat Program (Behavioral)	2022	N/A	$311	N/A
Residential Low Income and Age Qualifying HVAC HB 2789	2022	N/A	$381	N/A
Residential Manufactured Housing Program	2022	N/A	$421	N/A
Residential Multifamily Program	2022	N/A	$531	N/A
Residential IAQ Home Energy Report	2021	N/A	$662	N/A
Pump Hydro Storage (300 MW)	2027	15%	$794	N/A
Commercial Distributed Generation Program	2022	N/A	$1,095	N/A
Residential Smart Thermostat (DR)	2022	N/A	$2,950	N/A
Non Res IAQ Healthcare and Rental Property Owners	2021	N/A	$3,417	N/A
Residential IAQ Enhancements	2021	N/A	$5,076	N/A

Appendix 7A – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
White Oak Add TX#3 and TX#4 - DEV - Engineering Assessment	230	Mar-23	VA	2.0
Line #2154 and #19 Waller to Skiffes Creek Partial Rebuild	230	Mar-23	VA	18.4
La Crosse Sub - 115kV Delivery - DEV	115	Apr-23	VA	9.0
Farmwell - Add 3rd TX - DEV (Position #1)	230	Apr-23	VA	0.5
Waxpool 230kV Delivery - Add 4th Tx - DEV (Position #4)	230	Jun-23	VA	0.4
Line #227 Rebuild - Belmont to Beaumeade	230	Jun-23	VA	16.3
Gainesville 216192 Breaker Replacement	230	Jun-23	VA	0.5
Clover 230kV Breaker and Switch EOL Replacements	230	Jun-23	VA	2.8
Install a series reactor on the terminal of Line 2172	230	Jun-23	VA	3.0
Line #2113 Waller to Lightfoot Partial Rebuild	230	Jun-23	VA	9.0
Hourglass 230 kV Delivery - NOVEC (Two Silos)	230	Jun-23	VA	13.5
Youngs Branch 230 kV Delivery - DEV	230	Jun-23	VA	10.0
Line #2152 Uprate - Beaumeade to Buttermilk	230	Jun-23	VA	6.0
Line #9185 Uprate - Beaumeade to Paragon Park	230	Jun-23	VA	4.0
New Switching Station to Retire Line #5 Fork Union to Cunningham DP Segment (EOL)	115/230	Aug-23	VA	16.3
North Anna 230kV Equipment EOL Replacement	230	Aug-23	VA	2.4
Cloverhill 230kV Delivery - Add 3rd TX - DEV	230	Sep-23	VA	0.3
Mercury - Add 2nd TX - DEV	115	Sep-23	VA	0.3
Youngs Branch - Add 2nd TX - DEV	230	Nov-23	VA	0.8
Possum Point 500kV Breakers and Switches EOL Replacements	500	Nov-23	VA	8.1
Wakeman 230kV Delivery - DEV	230	Nov-23	VA	10.0
Line #581 Chancellor - Ladysmith Rebuild	500	Dec-23	VA	45.0
Global Plaza 230kV Delivery - DEV	230	Dec-23	VA	40.0
Line #550 Mount Storm to Valley Rebuild	500	Dec-23	WV/VA	476.0
Lines 265, 200, and 2051 Partial Rebuild (Loudoun-OX CPCN)	230	Dec-23	VA	11.5
Lines #229 Tarboro-Edgecombe NUG, Line #2167 Hathaway-Hornertown and Partial Line #55 Tarboro-Harts Mill EOL Rebuild	230	Dec-23	NC	40.0
Lines 238 & 249 Partial Rebuild	230	Dec-23	VA	7.0
Line 2002 Partial Rebuild	230	Dec-23	VA	4.3
Goose Creek 500-230kV TX	230/500	Dec-23	VA	40.0
Lockridge - Add Three TX - DEV	230	Jan-24	VA	1.5
Sinai - 115kV Delivery - Add 2nd TX - DEV	115	Feb-24	VA	0.5
Techpark Place SUB - New 230kV Delivery - DEV - Engineering Assessment	230	Apr-24	VA	25.0
Lincoln Park 230kV Delivery - DEV	230	Jun-24	VA	19.3
Mt Storm Substation GIS	500	Jun-24	VA	69.0
Cloud Sub - 230 kV Delivery (MEC) -Coleman Creek DP - Extend Line #235 Double Circuit Chase City	230	Jun-24	VA	81.0
Easters Sub - 230 kV Delivery (MEC) - Timber DP	230	Jun-24	VA	20.0
Line #224 Lanexa to Northern Neck Rebuild and second circuit	230	Jun-24	VA	112.2
Line #141 Balcony Falls to Skimmer and Line #28 Balcony Falls to Cushaw Rebuild	115	Jun-24	VA	30.9
Line 100 Harrowgate to Locks EOL Partial Rebuild	115	Jun-24	VA	9.3
Idylwood to Tyson's - New 230kV Line	230	Dec-24	VA	210.0
Line #254 Clubhouse-Lakeview EOL Rebuild	230	Dec-24	VA/NC	27.0
Peninsula - TX 4 Replacement and 230kV Ring Bus	230	Dec-25	VA	27.2
Dawkins Branch 230kV Delivery - NOVEC (Iron Mountain)	230	Dec-25	VA	16.0
Line #2010 Underground Relocation	230	Dec-25	VA	40.0
Idylwood - Convert Straight Bus to Breaker-and-a-Half	230	Dec-26	VA	159.0
Potomac Yards Undergrounding & Glebe GIS Conversion	230	Sep-27	VA	202.0

Appendix 8A – 2023 IDP Roadmap as filed in Case No. PUR-2023-00051

Integrated Distribution Planning Roadmap

Dominion Energy Virginia (or the "Company") defines integrated distribution planning ("IDP") as a consolidated process to address the capacity, performance, reliability, resilience, and distributed energy resource ("DER") integration needs of the distribution grid. In 2019, the Company presented a white paper regarding its preliminary plans to transition to an IDP approach (the "2019 White Paper"). Transitioning from traditional distribution planning processes to IDP is an industry-wide effort as the electric power system continues its fundamental shift from a world of centralized large-scale generation and a one-way power flow to the evolving paradigm of all type and number of DERs and a dynamic system with bidirectional and constantly changing power flows. The traditional distribution grid was not engineered and built for this evolving purpose. Consequently, the Company has actively engaged in IDP efforts and will continue to do so as IDP concepts further mature and evolve over the next decade and beyond.

This IDP roadmap provides an overview of the Company's efforts and successes thus far to transition to IDP and establishes tangible goals and timeframes as the Company's distribution planning processes shift toward IDP.

I. Background on Company IDP Efforts

In 2019, Dominion Energy Virginia presented the 2019 White Paper to provide a conceptual first look at its transition toward IDP.[1] The 2019 White Paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are integrated into the distribution system. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including:

- Centralization of the Company's organizational structure such that one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments;
- Development of an initial forecast of DERs by feeder;
- Publication of three hosting capacity tools, one that allows customers and developers to see the sections of the distribution system that may be more suitable to site new clean energy installations, one that reflects the ability to interconnect behind the meter DER to the distribution grid, and one that provides available hosting capacity for transportation electrification.

[1] *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2019-00154, Petition, Exhibit 1 (filed Sept. 30, 2019).

- Installation of two battery energy storage systems ("BESS") to study future non-wires alternatives;
- Continued construction of a microgrid to study future non-wires alternatives;
- Installation of advanced metering infrastructure ("AMI") across 71% of its distribution system, enabling the collection of premise-level load and voltage data;
- Initial installation of intelligent grid devices on selected feeders, enabling the collection of operational data that improves the accuracy of engineering models;
- Substation technology deployments that not only add enhanced situational awareness and increased system operability but provide increasingly granular data that refines the accuracy of the Company's engineering models.
- Initiated implementation of a DER management system ("DERMS"); and
- Participation in numerous research and development projects with EPRI and other industry entities focused on modernizing distribution grid planning, using automated processes and tools and data driven techniques to improve model data quality and further IDP goals and objectives.

The Company also engaged with Quanta Technology, LLC ("Quanta") to solidify the conceptual framework through which the Company views the components of IDP.

II. IDP Roadmap and Implementation Timeline

The Company indicated its intention to present in 2023 a roadmap for IDP that adds tangible goals and timeframes to IDP maturity. Figure 1 provides the Company's current roadmap for IDP (the "2023 IDP Roadmap" or the "Roadmap"). The 2023 IDP Roadmap shows the IDP-related capabilities which the Company intends to focus on over the next five years, the goal associated with each of those capabilities, and an estimated timeframe. The IDP concept is not static, and further changes are expected in the next decade, as the Roadmap is based on the information known by the Company at this time. The Roadmap gives higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements while balancing the resources (*e.g.*, personnel, funds) required to implement these components and the interdependencies among many of the components.

Appendix 8A – 2023 IDP Roadmap as filed in Case No. PUR-2023-00051

Figure 1: 2023 IDP Roadmap

IDP Component	Goal(s)	Estimated Timeframe
Integrated Capacity Analysis	- Develop static DER hosting capacity analysis for public viewing - Develop static electric transportation hosting capacity analysis for public viewing - Develop methodology to increase hosting capacity - Develop methodology to calculate dynamic hosting capacity - Develop methodology to estimate firm capacity contribution from variable DER	2021 to 2022 Begin in 2024 2025 – 2028 2025 - 2028
Comprehensive Distribution Grid Load and DER Forecasting	- Conduct competitive solicitation process for new forecasting software - Produce hourly (8760) forecasting on all feeders, including forecasts of load and DER	2022 to 2024
Distribution System Model	- Enhance the existing engineering model to reflect the low voltage system - Continue to improve the data quality and comprehensiveness of the engineering model	2023 Ongoing
DER Interconnection	- Develop software that can perform automated time series simulations for interconnection impact studies for utility-scale DERs	Begin in 2024
Non-wires Alternatives	- Assess load areas with anticipated capacity needs for use in the proposed NWA Program by leveraging EPRI's ADAPT engineering software	Begin in 2024
Distribution System Analysis	- Develop software that can perform automated detailed modeling for distribution planning studies - Develop software that can perform automated simulations for interconnection impact studies for utility-scale DERs - Develop software that can perform automated detailed modeling for selected engineering studies	Begin in 2024
Resiliency	- Engage with industry leaders (e.g., IEEE, EPRI) to develop standard	2024 - 2028

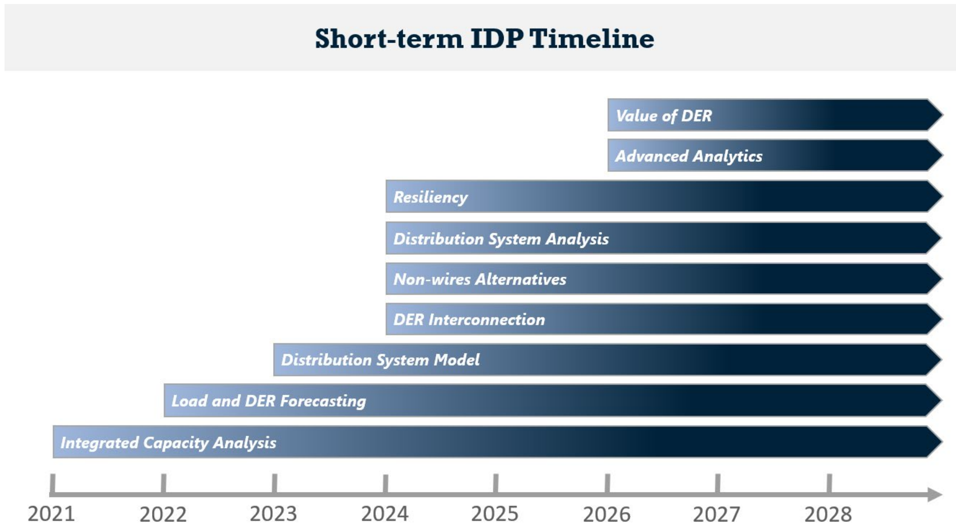
IDP Component	Goal(s)	Estimated Timeframe
	metrics for measuring and assessing grid resiliency	
Advanced Analytics	- Identify and define advanced analytics use cases and applications supporting IDP - Define data requirements for advanced analytics applications to IDP - Develop and implement advanced analytics pilot project(s)	2026 - 2028
Value of DER	- Develop a methodology to calculate the location value of DER for specific value streams of interest	2026 - 2027

As can be seen in Figure 1, the next step in the evolution toward IDP requires a fundamental shift in software solutions to those that can be scaled to meet the computational requirements of the advanced analyses required of a modern distribution grid. This will include investments in and adoption of innovative technologies (*e.g.*, cloud computing, big data platforms) as well as the Company's continued engagement with research entities to develop these solutions. It will also require increased staffing in multiple disciplines (*e.g.*, engineering, economics, data science) to implement the solutions and processes. These requirements are not unique to the Company but are recognized as necessary by distribution grid planning organizations throughout the industry.

In the 2019 White Paper, the Company published a figure showing the evolution of IDP over time as enabling technologies are deployed throughout the Grid Transformation Plan. While the components shown on that maturity curve remain key components to the IDP framework that the Company envisions, the Company has produced an implementation timeline (Figure 2) to align with the IDP Roadmap, lessons learned from its efforts over the past several years, and its engagement with EPRI and other industry activities.

Appendix 8A – 2023 IDP Roadmap as filed in Case No. PUR-2023-00051

Figure 2: IDP Timeline (2023)



The IDP Roadmap and implementation plans will set the foundation for achieving the Company's IDP vision. However, attaining that goal is expected to require more than 5 years, partly because some of these areas are still emerging and are expected to continue evolving within and beyond this timeframe; implementation plans therefore may need to be adjusted accordingly. Additionally, some of these components are necessarily projected in later years since regulatory and policy drivers, as well as commercial solutions, are either absent, incipient, or still being developed.