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BY ELECTRONIC DELIVERY

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Commonwealth of Virginia, ex rel. State Corporation Commission,
In re: Virginia Electric and Power Company's Integrated Resource Plan
filing pursuant to Va. Code § 56-597 et seq.
Case No. PUR-2020-00035

Dear Mr. Peck:

Please find enclosed for electronic filing in the above-captioned proceeding the 2020 Integrated Resource Plan of Virginia Electric and Power Company (the "2020 Plan") filed pursuant to § 56-597 *et seq.* of the Code of Virginia ("Va. Code"), the December 23, 2008 Order Establishing Guidelines for Developing Integrated Resource Plans issued by the State Corporation Commission of Virginia ("Commission") in Case No. PUE-2008-00099 ("Order Establishing Guidelines"), and the Integrated Resource Planning Guidelines ("Guidelines"). As required by the Commission, a reference index is enclosed that identifies the sections of the 2020 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 2020 Plan, the Company is filing two addenda under separate cover. Virginia Addendum 1 contains a Virginia residential bill analysis, and is being filed in public and extraordinarily sensitive versions. Virginia Addendum 2 contains the Grid Transformation Plan Document, and is being filed in public version only.

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.

Separate from these filings with the Commission, the Company is providing Commission Staff with the Guidelines schedules associated with the 2020 Plan in electronic format pursuant to Section E of the Guidelines, and is providing a copy of the 2020 Plan to members of the General Assembly pursuant to Va. Code § 56-599.

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

Very truly yours,

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

Vishwa B. Link

Enclosure

cc: Honorable D. Mathias Roussy, Hearing Examiner
Paul E. Pfeffer, Esq.
Audrey T. Bauhan, Esq.
Jennifer D. Valaika, Esq.
Sarah R. Bennett, Esq.
Service List

2020 Integrated Resource Plan Reference Index
Case No. PUR-2020-00035

Order / Guideline	2020 Plan Section	Requirement
Va. Code § 56-598 (1)	**Section 2.2** Alternative Plans	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;
Va. Code § 56-598 (2)	**2020 Plan**	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;
Va. Code § 56-598 (3)	**Section 2.2** Alternative Plans	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; and
Va. Code § 56-598 (4)	**2020 Plan** Reference Index	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.
Va. Code § 56-599 (A)	**2020 Plan**	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.
Va. Code § 56-599 (A)	**2020 Plan** Reference Index	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.
Va. Code § 56-599 (B)	**Chapter 5** Generation - Supply-Side Resources	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;
Va. Code § 56-599 (B)	**Chapter 5** Generation - Supply-Side Resources	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 2. Owning and operating electric power generation facilities;
Va. Code § 56-599 (B)	**Chapter 5** Generation - Supply-Side Resources	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 3. Building new generation facilities;
Va. Code § 56-599 (B)	**Section 4.2** Capacity Market Assumptions	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;
Va. Code § 56-599 (B)	**Chapter 6** Generation - Demand-Side Management	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;
Va. Code § 56-599 (B)	**Section 2.2** Alternative Plans	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;
Va. Code § 56-599 (B)	**Section 2.2** Alternative Plans	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;
Va. Code § 56-599 (B)	**Section 1.2** Virginia Clean Economy Act **Section 1.3** Regional Greenhouse Gas Initiative **Section 1.11** Other Environmental Regulation **Section 5.2.3** Environmental Regulations	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;
Va. Code § 56-599 (B)	**Section 2.3** NPV Results	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;

Order / Guideline	2020 Plan Section	Requirement
Va. Code § 56-599 (B)	**Chapter 8** Distribution	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
Va. Code § 56-599 (B)	**Chapter 6** Generation - Demand-Side Management	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 296 Enactment Clause 12	**Section 5.5.1** Supply-Side Resource Options **Section 9.3.1** Plan-Related Mandates	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.
Chapter 296 Enactment Clause 18	**Section 6.6** GTSA Energy Efficiency Analysis **Section 9.3.1** Plan-Related Mandates	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.
Guideline (A)	**Chapter 4** Generation - Planning Assumptions **Chapter 5** Generation - Supply-Side Resources	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.
Guideline (A)	See References for Guideline (F)(7) and Schedules	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).
Guideline (C)(1)	**Section 2.2** Alternative Plans **Appendix 2A** Plans A-D - Capacity & Energy **Section 4.1** Load Forecast **Appendix 4H** Projected Summer & Winter Peak Load & Energy Forecast for Plan B **Appendix 4I** Required Reserve Margin for Plan B	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.

Order / Guideline	2020 Plan Section	Requirement
Guideline (C)(2)	**Chapter 5** Generation - Supply-Side Resources **Chapter 6** Generation - Demand-Side Management	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.
Guideline (C)(2)(a)	**Section 4.2** Capacity Market Assumptions	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.
Guideline (C)(2)(b)	**Section 5.5** Future Supply-Side Generation Resources	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.
Guideline (C)(2)(c)	**Chapter 6** Generation - Demand-Side Management **Appendix 4L** Load Duration Curves	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.
Guideline (C)(2)(d)	**Chapter 4** Generation - Planning Assumptions	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.
Guideline (C)(3)	As Applicable	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.
Guideline (D)	**Chapter 1** Significant Development and Context for Integrated Planning Process	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.
Guideline (D)(1)	**Section 4.1** Load Forecast **Section 4.2** Capacity Market Assumptions	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.
Guideline (D)(2)	**Section 2.2** Alternative Plans **Chapter 3** Short-Term Action Plan	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.
Guideline (D)(3)	**Chapter 4** Generation - Planning Assumptions	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.
Guideline (D)(4)	**Section 4.1** Load Forecast	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.
Guideline (D)(5)	**Chapter 4** Generation - Planning Assumptions **Chapter 5** Generation - Supply-Side Resources **Chapter 6** Generation - Demand-Side Management	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.
Guideline (D)(6)	**Section 5.2** Evaluation of Existing Generation **Appendix 5J** Potential Unit Retirements **Appendix 5K** Planned Changes to Existing Generation Units **Appendix 5L** Environmental Regulations	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.

Order / Guideline	2020 Plan Section	Requirement
Guideline (D)(7)	**Section 2.2** Alternative Plans	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.
Guideline (E)	**2020 Plan**	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
Guideline (E)	**Chapter 3** Short-Term Action Plan	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.
Guideline (E)	**2020 Plan** Motion for Protective Order	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.
Guideline (E)	**2020 Plan** Proposed Notice	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.
Guideline (F)(1)	**Section 4.1** Load Forecast	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
Guideline (F)(1)(a)	**Appendix 4A** Total Sales by Customer Class (DOM LSE) (GWh) **Appendix 4B** Virginia Sales by Customer Class (DOM LSE) (GWh) **Appendix 4C** North Carolina Sales by Customer Class (DOM LSE) (GWh)	a. The most recent three-year history and 15-year forecast of energy sales (kWh) by each customer class
Guideline (F)(1)(b)	**Appendix 4H** Projected Summer & Winter Peak Load & Energy Forecast for Plan B **Appendix 4I** Required Reserve Margin for Plan 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
Guideline (F)(1)(c)	**Section 5.5** Future Supply-Side Generation	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
Guideline (F)(2)	**Chapter 1** Significant Developments and Context for Integrated Planning Process **Chapter 5** Generation - Supply-Side Resources	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.

Order / Guideline	2020 Plan Section	Requirement
Guideline (F)(2)(a)	**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	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.
Guideline (F)(2)(b)	**Section 5.5** Future Supply-Side Generation	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.
Guideline (F)(2)(b)(i)	**Appendix 3C** Comparison of Short-Term Action Plans **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	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.
Guideline (F)(2)(b)(ii)	**Section 5.5.1** Supply-Side Resource Options	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.
Guideline (F)(2)(c)	**Section 5.3** Generation Under Construction **Appendix 3A** Generation Under Construction **Appendix 3B** Planned Generation under Development	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
Guideline (F)(2)(d)	**Section 5.1.3** Non-Utility Generation **Appendix 5B** Other Generation Units	d. Non-Utility Generation. A separate list of all non-utility electric generating facilities included in the IRP, 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
Guideline (F)(3)	**Section 2.1** Capacity and Energy Position **Appendix 2A** Plans A-D - Capacity & Energy **Appendix 5Q** Summer Capacity Position for Plan B	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.

Order / Guideline	2020 Plan Section	Requirement
Guideline (F)(4)	**Appendix 4K** Wholesale Power Sales Contracts	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.
Guideline (F)(5)	**Chapter 6** Generation - Demand-Side Management **Appendices 6A to 6N**	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.
Guideline (F)(6)	**Chapter 5** Generation - Supply-Side Resources **Section 4.6.3** Solar Interconnection and Integration Costs	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.
Guideline (F)(7)	**Section 5.5.2** Levelized Busbar Costs **Appendix 5M** Tabular Results of Busbar **Appendix 5N** Busbar Assumptions	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.
Schedule 1	**Appendix 4H** Projected Summer & Winter Peak Load & Energy Forecast for Plan B	Peak load and energy forecast
Schedule 2	**Appendix 5G** Energy Generation by Type for Plan B (GWh)	Generation output
Schedule 3	**Appendix 5H** Energy Generation by Type for Plan B (%)	System output mix
Schedule 4	**Appendix 5R** Capacity Position for Plan B	Seasonal capability
Schedule 5	**Appendix 4J** Summer and Winter Peak for Plan B	Seasonal load
Schedule 6	**Appendix 4I** Required Reserve Margin for Plan B	Reserve margin
Schedule 7	**Appendix 5F** Existing Capacity for Plan B	Installed capacity
Schedule 8	**Appendix 5C** Equivalent Availability Factor for Plan B	Equivalent availability factor
Schedule 9	**Appendix 5D** Net Capacity Factor	Net capactiy factor
Schedule 10	**Appendix 5E** Heat Rates for Plan B	Average heat rate
Schedule 11	**Appendix 5O** Renewable Resources for Plan B	Renewable resources
Schedule 12	**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)	DSM programs
Schedule 13	**Appendix 5K** Planned Changes to Existing Generation Units	Unit size uprate and derate
Schedule 14	**Appendix 5A** Existing Generation Units in Service **Appendix 5B** Other Generation Units	Existing unit performance data

Order / Guideline	2020 Plan Section	Requirement
Schedule 15	**Appendix 3A** Generation under Construction **Appendix 3B** Planned Generation under Development **Appendix 5P** Potential Supply-Side Resources for Plan B	Planned unit performance data
Schedule 16	**Appendix 5Q** Summer Capacity Position for Plan B	Utility capacity position
Schedule 17	**Appendix 5S** Construction Forecast for Plan B	Construction forecast
Schedule 18	**Appendix 4R** Delivered Fuel Data	Fuel data
Case No. PUR-2020-00035 Order at 1-2	**Section 2.2** Alternative Plans **Section 4.10** VCEA-Related Assumptions	Dominion should model the costs and reliability impacts of the VCEA and other relevant legislation in its 2020 IRP. In addition to existing requirements, including the requirement to model a "least cost plan," Dominion's 2020 IRP shall: 1. Model the mandates and requirements of the VCEA and other relevant legislation based on the best available information, using reasonable and appropriately documented assumptions if necessary;
Case No. PUR-2020-00035 Order at 2	**Section 2.4** NPV Results	Dominion's 2020 IRP shall: 2. Calculate separately the net present value costs to customers of the least cost plan, the VCEA, and other relvant legislation including not only generation costs but also transmission and distribution costs;
Case No. PUR-2020-00035 Order at 2	**Section 2.6** Virginia Residential Bill Analysis **Va. Plan Addendum 1** Virginia Residential Bill Analysis	Dominion's 2020 IRP shall: 3. Calculate separately the annual bill impacts of the least cost plan, the VCEA, and additional legislation over each of the next ten years as compared to the bill of a residential customer using 1,000 kilowatt-hours per month as of May 1, 2020, including not only generation costs but also transmission and distribution costs;
Case No. PUR-2020-00035 Order at 3	**Section 4.1.3** Energy Efficiency Adjustment	Dominion's 2020 IRP shall: 4. For purposes of the modeling directed herein, other than the least cost plan, the Company shall model the impact of applicable energy efficiency requirements on the load forecast, separately as (a) an impact on the PJM peak load and energy sales forecast, and (b) a supply-side resource;
Case No. PUR-2020-00035 Order at 3	**Section 2.5** Transmission System Reliability Analysis **Section 7.5** Transmission System Reliability Analysis	Dominion's 2020 IRP shall: 5. Include an engineering analysis of the effects of the mandates and requirements of the VCEA and other relevant legislation on reliability of service to customers and identify any Company concerns regarding the impact of the mandates and requirements of the VCEA and other relevant legislation on the reliability of the Company's service; and
Case No. PUR-2020-00035 Order at 3	**Section 9.2** Effect of Infrastructure Programs on Overall Resource Plan	Dominion's 2020 IRP shall: 6. Include an analysis of how the infrastructure deployment and costs associated with the Company's electric distribution and transmission system programs, such as its Grid Transformation Plan, Underground Transmission Line Pilot, Battery Storage Pilot and Strategic Undergrounding Program, impact the Company's overall resource plan. Identify whether these distribution and transmission improvements enable broader deployments of distributed energy resources such as residential rooftop solar and whether such broader deployment displaces the need for traditional generation resources in the proposed build plans, include any reduction in costs associated with changes in the proposed build plans that would otherwise be required by the IRP.
Case No. PUR-2018-00065 Final Order at 11 Case No. PUR-2018-00065 Order on Reconsideration at 3	**Section 2.2** Alternative Plans **Section 4.9** Least-Cost Plan Assumptions	In future IRPs, the Company shall: 1. Model a true least-cost plan, as defined in the December 2018 Order. In the Order on Reconsideration, the Commission confirmed that this directive encompasses the concept that Commission-approved generation resources will not be required to be "modeled" for inclusion at all, but will appear as existing or under construction depending upon their development status.
Case No. PUR-2018-00065 Final Order at 11	**Section 4.1** Load Forecast	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.
Case No. PUR-2018-00065 Final Order at 11	**Section 4.7** Storage-Related Assumptions	In future IRPs, the Company shall: 3. Model battery storage using the most updated cost estimates available.
Case No. PUR-2018-00065 Final Order at 11	**Section 4.4** Commodity Price Assumptions	In future IRPs, the Company shall: 4. Model compliance with the Regional Greenhouse Gas Initiative.
Case No. PUR-2018-00065 Final Order at 11 Case No. PUR-2018-00065 Dec. 2018 Order at 5, n. 14	**Section 4.8** Gas Transportation Cost Assumptions	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

Order / Guideline	2020 Plan Section	Requirement
Case No. PUR-2018-00065 Final Order at 11-12 Case No. PUR-2018-00065 Order on Reconsideration at 5	**Section 4.6.1** Solar Capacity Factor	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.
Case No. PUR-2018-00065 Final Order at 12	**Chapter 8** Distribution **Va. Plan Addendum 2** GT Plan Document	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.
Case No. PUR-2018-00065 Final Order at 12, n. 49	**Appendix 5I** Solar and Wind Generating Facilities Since July 1, 2018	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.
Case No. PUR-2018-00065 Final Order at 12	**Appendix 3D** List of Planned Transmission Projects During the Planning Period	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.
Case No. PUR-2018-00065 Final Order at 12, n. 47 Case No. PUR-2018-00065 Thomas 2nd Rebuttal at 7	**Section 4.4.6** REC Price Forecasting Methodology **Appendix 4Q** Overview of PJM REC Price Forecasting	The Commission previously found the Company's REC price forecast methodology to be unreasonable (Dec. 2018 Order at 9-10). The Company proposes to work in consultation with the Staff to develop an appropriate REC price methodology, including appropriate risk scenarios, for upcoming IRP filings (Thomas Rebuttal at 7). We agree and so direct.
Case No. PUE-2016-00049 Final Order at 3 Case No. PUE-2015-00035 Final Order at 18	**2020 Plan** Reference Index	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.
Case No. PUE-2015-00035 Final Order at 10	**Section 5.4.4** Extension of Nuclear Licensing	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
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	**Section 5.5.3** Third-Party Market Alternatives	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
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	**Section 4.6.2** Solar Company-Build vs. PPAs **Section 5.5.3** Third-Party Market Alternatives	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
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	**Section 4.6.2** Solar Company-Build vs. PPAs **Section 5.5.3** Third-Party Market Alternatives	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
Case No. PUE-2015-00035 Final Order at 17	**Section 4.6.3** Solar Interconnection and Integration Costs	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
Case No. PUE-2013-00088 Final Order at 4	**Section 5.4** Generation Under Development **Section 5.4.4** Extension of Nuclear Licensing	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.

Order / Guideline	2020 Plan Section	Requirement
Case No. PUE-2013-00088 Final Order at 5-6	**Section 5.4.4** Extension of Nuclear Licensing	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.
Case No. PUE-2013-00088 Final Order at 8	**Section 6.7** Overall DSM Assessment	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.
Case No. PUE-2013-00088 Final Order at 8	**Section 4.4** Commodity Price Assumptions **Appendix 4O** ICF Commodity Price Forecasts **Appendix 4P** ICF Price Forecasts	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.

NOTICE TO THE PUBLIC
OF A FILING BY VIRGINIA ELECTRIC AND POWER COMPANY
OF ITS INTEGRATED RESOURCE PLAN
CASE NO. PUR-2020-00035

On May 1, 2020, Virginia Electric and Power Company (the "Company"), submitted to the State Corporation Commission ("Commission") its Integrated Resource Plan (the "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 C, the Commission will analyze the Company's Plan and make a determination as to whether the Plan is reasonable and in the public interest.

The Commission entered an Order Establishing Schedule for Proceedings ("Procedural Order") that, among other things, scheduled a public hearing at 9:30 a.m. on October 27, 2020, in the Commission's second floor courtroom located in the Tyler Building, 1300 East Main Street, Richmond, Virginia 23219, to receive opening statements, testimony, and evidence offered by the Company, respondents, and the Staff on the Company's Plan.

On [**date**], the Commission entered an Order for Notice and Comment ("Notice Order") that directed the Company to provide notice to the public and offered interested persons an opportunity to comment on the Company's Plan.

An electronic copy of the public version of the Company's Plan may be obtained, at no charge, by requesting it in writing from Jennifer D. Valaika, Esquire, McGuireWoods LLP, Gateway Plaza, 800 East Canal Street, Richmond, Virginia 23219, or jvalaika@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 public version of the Plan and other documents from the Commission's website: http://www.scc.virginia.gov/case.

On or before October 20, 2020, interested persons may file written comments concerning the issues in this case by following the instructions found on the Commission's website: http://www.scc.virginia.gov/case. All comments shall refer to Case No. PUR-2020-00035. In light of the ongoing public health emergency related to the spread of COVID-19, the Commission will subsequently schedule, if practicable, oral public comment in this matter; if scheduled, such will be noticed via Commission order and accompanying news release.

Any interested person may participate as a respondent in this proceeding by filing a notice of participation on or before August 4, 2020. Such notice of participation shall include the email addresses of such parties or 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-2020-00035. 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 Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2020-00035
Docket No. E-100, Sub 165

Filed: May 1, 2020

Table of Contents

List of Acronyms

Acronym	Meaning
2018 Plan	2018 Integrated Resource Plan
2019 Update	2019 Update to the 2018 Plan
2020 Plan	2020 Integrated Resource Plan
AC	Alternating Current
ACE Rule	Affordable Clean Energy Rule
AMI	Advanced Metering Infrastructure
BDM	Bass Diffusion Model
BESS	Battery Energy Storage System
BSER	Best System of Emissions Reduction
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CC	Combined-Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture and Sequestration
CFR	Code of Federal Regulations
CHP	Combined Heat and Power
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
CPP	Clean Power Plan
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(s)
DOM LSE	Dominion Energy Load Serving Entity
DOM Zone	Dominion Energy Zone
DSM	Demand-Side Management
DynADOR	Dynamic Assessment and Determination of Operating Reserves
EC	Enactment Clause
ECR	Emission Containment Reserve
EE	Energy Efficiency
EGU	Electric Generating Unit(s)
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitations Guidelines

Acronym	Meaning
EO43	Virginia Executive Order 43
EO80	North Carolina Executive Order 80
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EV	Electric Vehicle
FACTS	Flexible Alternative Current Transmission System
FERC	Federal Energy Regulatory Commission
FERC MOPR Order	June 29, 2018 FERC Order on MOPR
FRR	Fixed Resource Requirement
FSEIS	Final Supplemental Environmental Impact Statement
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
IEEE	Institute of Electrical and Electronics Engineers
IHS	IHS Markit
IPP	Independent Power Producer(s)
kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt Hours
LCOE	Levelized Cost of Energy
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MGD	Million Gallons per Day
MMBtu	Million British Thermal Unit(s)
Moody's	Moody's Analytics
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Megawatt Hours
NAAQS	National Ambient Air Quality Standards
NCDEQ	North Carolina Department of Environmental Quality
NCGS	North Carolina General Statute
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
Net CONE	Net Cost of New Entry
NO_x	Nitrogen Oxide
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	The National Renewable Energy Laboratory

Acronym	Meaning
NSRDB	National Solar Radiation Database
NUG	Non-Utility Generation or Non-Utility Generator
O&M	Operations and Maintenance
ODEC	Old Dominion Electric Cooperative
PJM	PJM Interconnection, L.L.C.
Plan	Integrated Resource Plan
PLEXOS	PLEXOS Model
PPA	Power Purchase Agreement
ppb	Parts Per Billion
PTC	Production Tax Credit
RACT	Reasonable Available Control Technology
RAIs	Requests for Additional Information
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
SCPC	Supercritical Pulverized Coal
SER	Safety Evaluation Report
SG	Standby Generation
SMR	Small Modular Reactor
SO_2	Sulfur Dioxide
STATCOM	Static Synchronous Compensators
Study Period	25-year Period of 2021 to 2045
SUP	Strategic Underground Program
TRC	Total Resource Cost
V2G	Vehicle-to-grid
Va. Code	Code of Virginia
VCEA	Virginia Clean Economy Act
VCHEC	Virginia City Hybrid Energy Center
VDEQ	Virginia Department of Environmental Quality
WHP	Waste Heat to Power

Introduction

Headquartered in Richmond, Virginia, Virginia Electric and Power Company (the "Company") currently serves approximately 2.6 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 20 states with electricity or natural gas.

The Company's supply-side portfolio consists of 20,063 megawatts ("MW") of generation capacity, including approximately 812 MW of non-utility generation ("NUG") resources. 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 58,000 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") Regional Transmission Organization ("RTO"), the operator of the wholesale electric grid in the Mid-Atlantic region of the United States. The 2020 Integrated Resource Plan (the "2020 Plan" or the "Plan") was prepared for the Dominion Energy Load Serving Entity ("DOM LSE") within PJM.

The Company files this 2020 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. The Company also files this 2020 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 2020 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.

This 2020 Plan covers the 15-year period beginning in 2021 and continuing through 2035 (the "Planning Period"), using 2020 as the base year. In certain instances, the Company evaluates the longer 25-year period of 2021 to 2045 (the "Study Period"). Overall, the 2020 Plan is 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

Throughout its history, the Company has been dedicated to the delivery of safe, reliable, and affordable energy to its customers. This dedication has included a strong movement towards a clean environment. For example, over the last two decades, by changing its generation mix and employing best practices, the Company's power generation fleet has reduced certain air emissions, including nitrogen oxide, sulfur dioxide, and mercury, by as much as 99%. The Company has also reduced its greenhouse gas emissions, lowering its carbon intensity by approximately 47% since 2000. Further, by adopting the latest technology and applying creative design, the Company is using less water in its operations through the use of air-cooled condensers.

The Company has now entered a new phase in its overall efforts to preserve the environment. On February 11, 2020, the Company's parent company—Dominion Energy—announced a significant expansion of its greenhouse gas emissions reduction goals, establishing a new company-wide commitment to achieve net zero carbon dioxide ("CO_2") and methane emissions by 2050. Net zero does not mean eliminating all emissions, but instead means that any remaining emissions are balanced by removing an equivalent amount from the atmosphere. For example, this can occur through carbon capture, reforestation, or negative-emissions technologies such as renewable natural gas. This strengthened commitment to net zero CO_2 and methane emissions builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions consistent with the findings of the United Nations' Intergovernmental Panel on Climate Change. The commitment is also a recognition of the increased expectations and interest among customers, policy makers, and employees in building a clean energy future.

This net zero CO_2 and methane emissions commitment from Dominion Energy parallels the commitments made to clean energy in both Virginia and North Carolina. In Virginia, the Virginia Clean Economy Act (the "VCEA") will become law effective July 1, 2020. The VCEA establishes a mandatory renewable portfolio standard ("RPS") aimed at 100% clean energy from the Company's generation fleet by 2045. In furtherance of this mandatory RPS, the VCEA requires the development of significant energy efficiency, solar, wind, and energy storage resources; it also mandates the retirement of all generation units that emit CO_2 as a byproduct of combustion by 2045, unless the retirement of a particular unit would threaten grid reliability and security. Based on other new legislation, the Company expects that Virginia will soon become a full participant in the Regional Greenhouse Gas Initiative ("RGGI")—a regional effort to cap and reduce CO_2 emissions from the power sector. In North Carolina, the Clean Energy Plan, a compilation of policy and action recommendations developed through a public stakeholder process, sets a statewide carbon neutrality goal by 2050.

This 2020 Plan focuses on presenting alternative plans that set the Company on a trajectory to achieve these clean energy targets. Indeed, the Company has already begun to transition its generation fleet, as well as its transmission and distribution systems, to achieve a cleaner future. Examples of this ongoing transition include:

- The retirement of over 2,200 MW of coal-fired and inflexible, higher cost oil- and natural gas-fired generation over the past ten years;
- The construction of approximately 198 MW of solar generation over the past ten years, with an additional 198 MW of solar generation currently under construction;
- The procurement of approximately 874 MW of solar NUGs over the past ten years;
- The continued work to extend the licenses of the Company's nuclear units at Surry and North Anna;
- The construction of the Coastal Virginia Offshore Wind ("CVOW") demonstration project, along with the development of a larger build-out of offshore wind generation off the coast of Virginia;
- The continued transformation of the Company's 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; and
- The continued work associated with energy storage technology, including the development of a new pumped storage hydroelectric facility in Virginia and the deployment of three battery energy storage system ("BESS") pilot projects.

Over the long term, however, 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 large-scale energy storage, hydrogen, advanced nuclear, and carbon capture and sequestration, all of which have the potential to significantly reduce greenhouse gas emissions.

In this 2020 Plan, the Company presents four alternative plans (the "Alternative Plans"). Except for Alternative Plan A, all Alternative Plans assume that Virginia is a full RGGI participant.

- Plan A – This Alternative Plan presents a least-cost plan that estimates future generation expansion where there are no new constraints, including no new regulations or restrictions on CO_2 emissions. Plan A is presented for cost comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, this Alternative Plan does not represent a realistic state of relevant law and regulation.

- Plan B – This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues. While Plan B—and indeed all Alternative Plans—incorporate only known, proven technologies, the Company fully expects that new technologies could take the place of today's technologies over the Study Period. Overall, Plan B is the lowest cost of Alternative Plans B, C, and D, decreases the reliance on outside markets to meet customer demand and produces similar regional CO_2 emissions as Plans C and D. Over the Study Period (*i.e.*, 2021 to 2045), this Alternative Plan includes the development of approximately 31 gigawatts ("GW") of solar capacity, approximately 5 GW of offshore wind capacity, and approximately 5 GW of new energy storage.

- Plan C – This Alternative Plan uses similar assumptions as Plan B, but retires all Company-owned carbon-emitting generation in 2045, resulting in close to zero CO_2 emissions from the Company's fleet in 2045. To reach zero CO_2 emissions from the Company's fleet in 2045, Plan C significantly increases the amount of energy storage resources and the level of imported power. Specifically, in the last ten years of the Study Period, Plan C requires the addition of approximately 1 GW of incremental solar capacity and approximately 4.8 GW of incremental energy storage as compared to Plan B. In addition, beginning in Year 16 of Plan C, the Company's transmission import capacity would need to double to approximately 10.4 GW total in order to support the Company's winter import needs, as well as spring and fall export needs. This imported power from PJM would come in part from CO_2-emitting generation, meaning that while CO_2 emissions from the Company's fleet would be near zero, regional CO_2 emissions would remain at similar levels as Plan B.

- Plan D – This Alternative Plan uses similar assumptions as Plan C but changes the capacity factor assumption for future solar resources from 25% to 19%. As a result, Plan D significantly increases the amount of solar resources needed to reach zero CO_2 emissions in 2045. Specifically, over the Study Period, this Plan includes approximately 9.2 GW of incremental solar capacity and approximately 4.8 GW of incremental energy storage as compared to Plan B, which is approximately 8.1 GW more solar capacity than Plan C. Like Plan C, beginning in Year 16 of Plan D, the Company's transmission import capacity would need to be doubled to approximately 10.4 GW total in order to support the Company's winter import needs, as well as spring and fall export needs. Accordingly, also like Plan C, regional CO_2 emissions would remain at similar levels as Plan B based on the increased dependence on imported power. Notably, the lower 19% capacity factor is based on the historical performance of the Company's solar generation resources as required by an SCC order; in the Company's view, this 19% capacity factor does not represent a reasonable estimate of solar generation's expected potential.

The following table presents a high-level summary of the Alternative Plans:

Executive Summary Table: 2020 Plan Results

	Plan A	Plan B	Plan C	Plan D
NPV Total ($B)	$44.3	$66.2	$78.6	$80.8
Approximate CO_2 Emissions from Company in 2045 (Tons)	24 M	10 M	0	0
Approximate CO_2 Emissions Regionally in 2045 (Tons)	34 M	4 M	4 M	5 M
Solar (MW)	6,720 15-year 11,520 25-year	15,920 15-year 31,400 25-year	15,920 15-year 32,480 25-year	18,800 15-year 40,640 25-year
Offshore Wind (MW)	--- 15-year --- 25-year	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year
Storage (MW)	--- 15-year --- 25-year	2,714 15-year 5,114 25-year	2,714 15-year 9,914 25-year	2,714 15-year 9,914 25-year
Natural Gas-Fired (MW)	1,940 15-year 3,531 25-year	970 15-year 970 25-year	970 15-year 970 25-year	970 15-year 970 25-year
Import / Export Capability (MW)	5,200 15-year 5,200 25-year	5,200 15-year 5,200 25-year	5,200 15-year 10,400 25-year	5,200 15-year 10,400 25-year
Retirements (MW)	3,030 15-year 4,651 25-year	3,183 15-year 5,414 25-year	3,183 15-year 13,978 25-year	3,183 15-year 13,978 25-year

As can be seen in the table above, Alternative Plans B through D are very similar over the first 15 years. This general alignment over the Planning Period sets a common pathway for the Company to pursue now while allowing new technologies to mature. All Alternative Plans include 970 MW of natural gas-fired combustion turbines ("CTs") as a placeholder to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities. While all Alternative Plans in this 2020 Plan incorporate only known, proven technologies, the Company fully expects that new technologies could take the place of today's technologies over the Study Period. The Company intends to explore all new and promising technologies that support a cleaner future and that will enable the Company to achieve its environmental goals, as well as the goals of Virginia and North Carolina. The Company will provide information on these developments in future Plans and update filings.

Based on the current state of technology and the need for technological advances to truly achieve a cleaner future, Alternative Plans B through D as presented in this 2020 Plan all pose challenges over the long term.

Alternative Plans B through D factor in the implementation of energy efficiency programs and measures to achieve both 5% total annual energy savings by 2025, as targeted by the VCEA, and $870 million in proposed spending by 2028, as required by the Grid Transformation and Security Act of 2018 (the "GTSA"). The Company has modeled these objectives by supplementing the Company's approved and pending DSM programs with a generic level of energy efficiency at a fixed price. This approach is a theoretical assumption used for planning purposes only. In reality, the level of energy efficiency savings included in this 2020 Plan may not materialize in the same manner as modeled due to many outside factors. These factors include the ability of future vendors to deliver program savings at the assumed fixed price, the desire of customers to participate in the program at that price, and the effectiveness of the program to be administered at that price. The modeled costs and level of savings attributable to generic energy efficiency are thus placeholders as future phases of actual energy efficiency programs are developed and implemented.

From a permitting perspective, all Alternative Plans include large quantities of solar capacity located in Virginia. In fact, to meet customers' demand, Alternative Plans B through D require between 31,400 MW and 40,640 MW of new solar capacity by 2045. Given current technology, 31,400 MW of solar generating capacity in the Commonwealth would require the land use of 490 square miles. This land mass is nearly 25% larger than Fairfax County, Virginia, or the equivalent of nearly 237,000 football fields. Utilization of such a large land mass area for energy generation will likely encounter local and environmental permitting issues.

The large quantities of solar capacity in Alternative Plans B through D also pose challenges from a technical perspective. A key component included in the traditional design of the North American electric power grid is the inertia from many existing traditional turbines to create a reservoir of kinetic energy. This kinetic energy automatically provides grid support by balancing the myriad of instantaneous discrepancies between generation and load at any moment in time. Inverter-based generation such as intermittent solar and wind resources do not provide such a reservoir of kinetic energy. Therefore, the retirement of traditional generation units coupled with the addition of large quantities of intermittent renewable generation will adversely affect both electric system reliability and the Company's ability to restore the system in the event of a large-scale blackout. Transmission planning work has begun, but more planning analysis is necessary to model the grid under different conditions to assure system reliability, stability, and security with the retirement of traditional generation. Although Plans B through D show significantly reduced carbon emissions by 2045 associated with these projected retirements, additional transmission and distribution projects potentially needed to address system reliability and security have not been fully assessed and evaluated in this 2020 Plan. The Company will provide the results of these additional analyses in future Plans and update filings.

In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

In Alternative Plan B, the Company preserved approximately 9,700 MW of efficient natural gas-fired generation units to address these future system reliability, stability, and energy independence issues. In future Plans, these units could be replaced by new types of generation such as small modular reactors. These units could also be transformed into low-carbon or carbon-free generation by installing new technologies such as carbon capture sequestration or refueling these units with hydrogen or renewable natural gas. For example, the Company could use excess energy from renewable facilities during periods of lower demand (*i.e.*, spring and fall) to create and store hydrogen fuel that could subsequently be used in these gas-fired generators. When hydrogen fuel is used in gas-fired generators, the byproduct is water rather than CO_2. The Company will continue to study these types of innovative alternatives and will, when and if feasible, reflect those alternatives in future Plans.

Unlike Alternative Plan B, Alternative Plans C and D model the retirement of all Company-owned carbon-emitting generation by 2045. If the Company retires all carbon-emitting generation units by 2045 as modeled in Alternative Plans C and D, given current energy storage and solar technology—and even with approximately 10,000 MW of new incremental storage—customers' winter peak load demand could not be met unless grid transmission import capacity is approximately doubled. Doubling transmission import capacity is a significant task that requires additional study, and would require significant capital expenditures and permitting challenges. Even if this import capacity could be doubled from a technical perspective, Virginia would become dependent on other jurisdictions to meet its winter peak needs, which, in the Company's view, presents an unacceptable risk. This risk increases as neighboring states elect to pursue the development of significant solar resources similar to Virginia and face similar challenges meeting winter peak load demand. Doubling transmission import capacity as modeled in Plans C and D would also result in similar regional CO_2 emissions as Alternative Plan B because the imported power from PJM would come in part from CO_2-emitting generation.

Separate from the proposed build plans and related system upgrades, Alternative Plans B through D include foundational investments to transform the Company's electric distribution grid to facilitate the integration of DERs, to enhance reliability and security, and to improve the customer experience (the "Grid Transformation Plan"). The Grid Transformation Plan will prepare the Company's distribution grid to support the cleaner future envisioned by Virginia, North Carolina, and the Company. For example, with advanced metering infrastructure ("AMI") and a new customer information platform, the Company can offer advanced rate options to all customers across its system targeted at energy efficiency and demand reduction. A transformed grid will also support electric vehicle ("EV") adoption while minimizing the effect of EV charging on the distribution grid, thus maximizing the benefits of electrification. Foundational components of the Grid Transformation Plan, such as AMI, deployment of intelligent grid devices, advanced control systems, and a robust and secure telecommunications network, are necessary to integrated distribution planning that can produce inputs into future Plans.

The Company fully supports the transition towards clean energy without compromising reliability, and stands ready to meet the challenges discussed with continued study, technological advancement, and innovation. Importantly, as noted above, the first 15 years of Alternative Plans B through D present very similar paths forward; the dramatic differences between the Alternative Plans occur during the last ten years of the 25-year Study Period. This alignment between Alternative Plans B through D over the 15-year Planning Period creates a common pathway for the Company to pursue now while allowing new technologies to emerge and mature, and allowing analysis and study to continue. Accordingly, for this 2020 Plan, the Company recommends a path forward that substantially aligns with the first 15 years of Alternative Plans

B through D. Over the longer-term, however, based on current technology and this "snapshot in time," the Company recommends Alternative Plan B.

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, 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. 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.

Chapter 1: Significant Developments and Context for Integrated Planning Process

The Company's comprehensive planning process considers significant emerging policy, market, regulatory, and technical developments that could affect its operations and, in turn, its customers.

1.1 Dominion Energy Net Zero Target

In February 2020, Dominion Energy announced its commitment to net zero CO_2 and methane emissions across its nationwide electric generation and natural gas infrastructure operations by 2050. The goal covers CO_2 and methane emissions, the dominant greenhouse gases ("GHGs"), from electricity generation and gas infrastructure operations. The strengthened commitment builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions.

Net zero is a framework under which companies effectively achieve "zero" emissions through a combination of actions to reduce emissions at their own facilities and through initiatives such as reforestation and various other verifiable measures that reduce emissions. By 2050, Dominion Energy is committed to achieve net zero CO_2 and methane emissions across all of its electric and natural gas operations in all 20 states where it does business, which is the timeframe referenced in climate work published by the United Nations Intergovernmental Panel on Climate Change. Dominion Energy has been actively lowering its CO_2 and methane emissions by employing existing technology and resources, such as extending the licenses of its zero-carbon nuclear fleet; rapidly expanding wind and solar resources; continuing to rely on low-carbon natural gas; promoting the use of electric vehicles and energy efficiency; and investing in renewable natural gas. Dominion Energy continuously monitors internal operations and external factors (*e.g.*, technology, public policy, stakeholder feedback) to assess for appropriateness in all of its sustainability commitments, including its climate goals.

Achieving net zero CO_2 and methane emissions will require technological advancements in the utility sector and broader investments in technology across the entire economy in the long term. In the near term, Dominion Energy will continue to explore new technologies to accelerate future progress. This includes an industry-leading methane emissions reduction program that is one of the most aggressive and sweeping in the nation. Dominion Energy has reduced methane emissions from its gas infrastructure by approximately 25% since 2010 and has committed to achieving a 65% reduction by 2030 and an 80% reduction by 2040. In addition, Dominion Energy has partnered with the nation's largest hog and dairy producers to turn farm waste into clean renewable natural gas. By 2029, these projects will reduce methane emissions from the nation's farms by the same amount as taking 650,000 cars off the road or planting 50 million new trees each year. Overall, Dominion Energy is committed to pursuing all reasonable paths to assure its goal of net zero CO_2 and methane emissions is achieved while maintaining the reliability that customers demand.

1.2 Virginia Clean Economy Act

The VCEA—Senate Bill No. 851 and House Bill No. 1526 from the 2020 Regular Session of the Virginia General Assembly—was signed into law on April 11, 2020, and becomes effective July

1, 2020. The VCEA includes provisions that institute a mandatory renewable portfolio standard, enhance renewable generation and energy storage development, require the retirement of certain generation units, establish energy efficiency targets, and expand net metering.

- The VCEA establishes a mandatory RPS that:
  - Includes RPS annual requirements based on a percentage of non-nuclear electric energy sold by the Company, reaching 100% by 2045;
  - Sets standards for meeting the RPS requirements, including 1% from distributed generation and 75% from resources located in the Commonwealth;
  - Requires the development of renewable generation and energy storage resources, as discussed further below;
  - Requires the retirement of generation units that emit CO_2 as a byproduct of combustion, as discussed further below;
  - Recognizes the benefits and necessity of nuclear license extensions; and
  - Establishes penalties if the Company does not meet the RPS requirements in any compliance year.

- The VCEA requires the Company to petition the SCC for approval to construct or purchase up to 5,200 MW of offshore wind generation and declares such offshore wind generation to be in the public interest if those facilities achieve commercial operation by 2034.
  - The costs associated with between 2,500 MW and 3,000 MW of utility-owned offshore wind are presumed to be reasonably and prudently incurred if the facilities achieve commercial operation by 2028, the Company complies with mandated competitive procurement requirements, and the levelized cost of energy ("LCOE") does not exceed 1.4 times the LCOE of a CT as estimated by the U.S. Energy Information Administration in 2019.

- The VCEA requires the Company to petition the SCC for approval to construct or purchase 16,100 MW of solar or onshore wind generation located in the Commonwealth.
  - The Company must petition for approval to construct or purchase the 16,100 MW of solar or onshore wind generation on the following schedule:
    - 3,000 MW by 2024;
    - 6,000 MW by 2027;
    - 10,000 MW by 2030; and
    - 16,100 MW by 2035.
  - Thirty-five percent of the solar and onshore wind generating capacity must be procured from third-party-owned facilities through power purchase agreements ("PPAs").
  - The 16,100 MW development must include 1,100 MW of small-scale solar (*i.e.*, projects less than 3 MW), and 200 MW of solar placed on previously developed project sites.

- The VCEA requires the Company to petition the SCC for approval to construct or purchase 2,700 MW of energy storage resources located in the Commonwealth and declares such resources to be in the public interest provided those facilities achieve commercial operation by 2035.

- At least 35% of such energy storage capacity must be procured from third-party-owned resources through PPAs.
- Ideally, at least 10% of energy storage resources should be located behind the meter.
- The Company may procure a single energy storage project up to 800 MW, allowing for construction of a pumped hydroelectric storage facility.

- The VCEA mandates the retirement of generation units that emit CO_2 as a byproduct of combustion on the following schedule, unless the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric service:
  - Chesterfield Units 5 and 6 (coal) and Yorktown Unit 3 (heavy oil) by 2024;
  - Altavista, Hopewell, and Southampton (biomass) by 2028; and
  - All remaining generation units that emit CO_2 as a byproduct of combustion by 2045.

- The VCEA encourages energy efficiency programs and measures that target a 5% reduction in energy sales (as measured against 2019 jurisdictional electricity sales) by 2025.
  - The SCC would evaluate the programs in 2025 and establish the going-forward savings targets in three year increments.
  - If targets are not achieved, costs of energy efficiency programs would be recovered without a margin, and the SCC may not certificate new generation units that emit CO_2 as a byproduct of combustion unless a threat to system reliability or security exists.

- The VCEA expands the net metering cap from 1% to 6% of the previous year's adjusted peak load forecast, with 1% reserved for low-income customers.
  - At the earlier of 2025 or after 3% of the previous year's peak demand is reached, the SCC will initiate a proceeding to determine a new net metering rate.

The VCEA formalizes the administrative policy goals set by Virginia Governor Northam in September 2019 through Executive Order 43: Expanding Access to Clean Energy and Growing the Clean Energy Jobs of the Future ("EO43"). EO43 established statewide goals and targets for reducing carbon emissions. Specifically, EO43 included a goal that by 2030, 30% of the Commonwealth's electric system would be powered by renewable energy sources. By 2050, the goal was for 100% of Virginia's electricity to be produced from carbon-free sources such as wind, solar, and nuclear. In establishing a mandatory RPS, the VCEA sets forth a framework to meet the goals of EO43.

1.3 Regional Greenhouse Gas Initiative

RGGI is a collaborative effort to cap and reduce CO_2 emissions from the power sectors of participating states, which currently include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

The concept of Virginia joining RGGI is not new. Starting with former Governor McAuliffe's Executive Directive 11, Virginia began a process that has thoroughly investigated RGGI and the effect of Virginia's participation. On May 27, 2019, the Virginia Department of Environmental Quality ("VDEQ") published a final rule that established a state cap-and-trade program for electric generation units ("EGUs") in Virginia (the "VDEQ Carbon Rule"). The VDEQ Carbon Rule became effective on June 26, 2019.

In 2019, the state budget bill (signed by Virginia Governor Northam) prohibited VDEQ from continued work on the VDEQ Carbon Rule. The VDEQ Carbon Rule thus included a section that allowed for delayed implementation. Specifically, implementation of most elements of the program, including requirements for holding and surrendering CO_2 allowances, was delayed until further authorization for appropriating funding to implement the program. Nevertheless, the VDEQ Carbon Rule included specific near-term requirements for affected entities, including:

- A requirement to submit to the VDEQ by August 25, 2019, the annual net electric output in megawatt-hours ("MWh") for calendar years 2016, 2017, and 2018 for each EGU subject to the rule, which the VDEQ would use to determine the CO_2 allowance allocations for the initial control period; and

- A requirement to submit to the VDEQ by January 1, 2020, a complete CO_2 budget permit application for affected sources with an applicable EGU subject to the program.

The Company complied with these requirements by the required deadlines. While the final VDEQ Carbon Rule removed specific references to RGGI, the rule remained structured in a way that would allow for the Virginia program to link with a regional program such as RGGI.

Other key elements of the VDEQ Carbon Rule as finalized are:

- A starting (baseline) statewide CO_2 emissions cap of 28 million tons in 2020, reduced by about 3% per year through 2030, resulting in a 2030 cap of 19.6 million tons (however, the rule allowed for adjustment of the starting cap for delayed implementation);

- No references to continued cap reductions after 2030 that the VDEQ had included in prior versions of the rule;

- Reinstated language to clarify that affected units under the rule would only have to hold allowances for emissions associated with fossil fuel combustion, assuring that the Company's Virginia City Hybrid Energy Center ("VCHEC") would not have to hold allowances for emissions related to biomass co-firing; and

- No opportunity to generate offsets from projects in Virginia, though the rule includes a provision that would recognize eligible emissions offsets from other participating states in a regional trading program. The VDEQ has indicated it may re-evaluate offset provisions during the next program review.

In 2020, legislation passed the Virginia General Assembly related to RGGI. In addition to the legislative provisions of the VCEA discussed in Section 1.2, the VCEA also directs Virginia's participation in a carbon trading program through 2050. Separate legislation provides for Virginia's participation in RGGI. Specifically, the Clean Energy and Community Flood Preparedness Act—Senate Bill No. 1027 and House Bill No. 981 from the 2020 Regular Session of the Virginia General Assembly—will become law effective July 1, 2020. This Act authorizes Virginia to join RGGI directly and authorizes the VDEQ to implement the VDEQ Carbon Rule. Given the passage of this Act combined with Virginia's previous efforts associated with RGGI participation, the Company believes it is highly probable that Virginia will become a full RGGI participant.

1.4 North Carolina Clean Energy Plan

In October 2018, North Carolina Governor Cooper issued Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy ("EO80"). Among other goals, EO80 set a statewide GHG reduction goal of 40% by 2025 (using a 2005 baseline), an electric power sector goal of 70% GHG reduction by 2030 (using a 2005 baseline), and a carbon neutrality goal by 2050. EO80 also required the North Carolina Department of Environmental Quality ("NCDEQ") to develop a North Carolina Clean Energy Plan to establish pathways for achieving the EO80 goals. After the public comment period, NCDEQ issued the final North Carolina Clean Energy Plan in October 2019. NCDEQ has also established stakeholder groups to establish recommendations for policy designs to align with EO80 goals.

1.5 Need for a Modern Distribution Grid

Electricity has become a basic need, vital to the economy, to public safety, and to customers' way of life. Critical services and infrastructure increasingly rely on electricity, including homeland security, large medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pumping facilities. As society has grown more dependent on electricity, customers expect both highly reliable service and easy access to their energy usage information so that they can make informed decisions about their consumption. Another fundamental change in the energy industry is the emerging shift within the transportation industry as it continues toward electrification of personal vehicles, fleets, and mass transit. Another vital resource powered by electricity is the internet, which drives commerce and everyday life. Even a brief interruption or power quality anomaly at, for example, a data center can be catastrophic for both the data center itself and the businesses that rely on that data center. While service interruptions have always been an inconvenience in modern society, the safe, reliable, and consistent delivery of power has never been more important than it is today.

In addition to the increasing importance of reliable electric service, the rise of DERs requires a fundamental change to the electric grid. With DERs, electricity is now flowing onto the distribution system from multiple points. The distribution system that was designed for the one-way flow of electricity must now accommodate the two-way flow of electricity. In addition, the intermittent nature of some of these DERs resulting from weather variability creates power fluctuations not typical of traditional generation resources. Propagated in an arbitrary manner, DERs are independent nodes that can disrupt traditional grid power quality and reliability. But when paired with investments to increase visibility on and control of the distribution system, DERs can transform into a system resource that can be equitably managed to maximize the value of other available resources, and potentially offset the need for future "traditional" generating assets or grid upgrades, all while maintaining reliable service to customers.

Because DERs rely on the distribution system to deliver the electricity they produce, a resilient distribution system is vital to maximizing the value of DERs. Day to day outages, as well as major weather events, not only cause prolonged outages for customers, but also prevent DERs from delivering electricity. The distribution system must be reliable and resilient so that it can operate for DERs like the transmission system operates for large, centralized generators.

Foundational investments to transform the distribution grid will allow the Company to use the distribution system differently than it does today, all for the benefit of customers. Transformational investments in infrastructure resilience, AMI, a customer information platform, intelligent grid devices, automated control systems, and advanced analytics will enable the Company to improve operations (*e.g.*, more efficient restoration, reducing truck rolls, more predictive and efficient maintenance, and increased visibility), better forecast load shape, and better predict future behaviors (*e.g.*, identifying and fixing grid problems before an outage occurs), resulting in a better, more informed customer experience that meets customers' changings needs and expectations.

1.6 Forward Capacity Markets

The Company is closely following the developments in the PJM forward capacity market, including the Federal Energy Regulatory Commission ("FERC") Minimum Offer Price Rule ("MOPR") proceedings, and is considering its options, including election of the fixed resource requirement ("FRR") alternative. As discussed further in Section 4.2, however, the modeling for this 2020 Plan is indifferent to whether the Company participates in the PJM forward capacity market or elects the FRR alternative.

1.6.1 Minimum Offer Price Rule

PJM has had the MOPR concept in place since the late 2000s. MOPR is designed to prevent price suppressive behavior of resources that participate in PJM's Reliability Pricing Model ("RPM") capacity market. This rule requires new resources to bid into the capacity market at or above the resource type's net cost of new entry ("Net CONE"). CONE reflects a resource's capital investments and fixed operations and maintenance ("O&M") expenses. Net CONE refers to CONE value net of the expected energy and ancillary market revenues. Net CONE, therefore, reflects the capacity revenue the resource would need to remain profitable.

Some generation entities filed a complaint at FERC in 2017 arguing the lack of effectiveness of capacity markets in PJM due to state subsidies. Specifically, the generation entities argued that state subsidies could have the effect of lowering capacity market clearing prices because the units receiving subsidies were receiving additional revenue that lowered their need from the market.

On June 29, 2018, FERC issued an order finding that PJM's Open Access Transmission Tariff was unjust and unreasonable because the MOPR "fail[ed] to address the price-distorting impact of resources receiving out-of-market support" (the "FERC MOPR Order"). On December 19, 2019, FERC directed PJM to expand MOPR to address state-subsidized resources, with very limited exemptions. Although one of the exemptions included existing self-supply resources, the FERC MOPR Order would subject new resources from self-supply entities (such as the Company) to the expanded MOPR. Because there is no guarantee that the capacity market would clear above a resource's Net CONE value (which it never has), the capacity market revenues for most new resources, including those from self-supply entities, would be uncertain.

On March 19, 2020, PJM submitted its compliance filing on the FERC MOPR Order. Specifically, PJM's compliance filing sets the Net CONE and net avoidable cost rate values for necessary resource classes; offers flexibility for unit-specific offer reviews; addresses circumstances where resources elect the competitive exemption and receive a subsidy later; and establishes auction timing for the 2022/2023 delivery year and beyond.

1.6.2 Fixed Resource Requirement Alternative

The Company joined PJM in 2005. In 2007, in order to assure reliability, PJM instituted the RPM, which created a forward generation capacity market that placed a value on reliability. PJM's existing rules allow vertically-integrated utilities to opt out of the capacity market by electing the FRR alternative. American Electric Power Company, the parent of Appalachian Power Company, has been the only significant utility in PJM to use this option since 2007.

The Company has participated in the RPM forward capacity market since 2007. One advantage of the RPM forward capacity market is that it draws upon resources from across PJM to ensure that sufficient supply- and demand-side resources are secured three years before they may be called upon to serve customer load. The market will pay those resources for their availability when the future delivery year arrives. This forward market provides a financial incentive and a degree of certainty designed to incentivize investment in new and existing resources beyond what is available through PJM's energy and ancillary services markets. The three-year forward auctions in the RPM have resulted in auction clearing reserve margins in the approximately 19% to 24% range—in excess of PJM's installed reserve margin—which means that the DOM LSE must purchase about 20% more unforced capacity than its forward load forecast. RPM participation considers a variable resource requirement defined by a demand curve in relation to supply offers; where supply offers cross the demand curve creates the capacity clearing price and the reserve margin for load. Based on the recent FERC MOPR Order, virtually all new generation resources will need to offer at Net CONE or an otherwise calculated market seller offer cap—which could be above the RPM market clearing price—resulting in $0 revenue for these un-cleared resources.

As an alternative to the RPM forward capacity market, PJM permits the FRR construct. The Company is eligible to elect the FRR alternative because it is an investor-owned utility. One of the key requirements for FRR is to demonstrate that sufficient generation resources are available to meet the reliability requirement for the FRR service area. The reliability requirement for the FRR service area is the forward load forecast plus the target reserve margin. This is one of the primary differences between RPM and FRR, as the PJM coincident peak target reserve margin for FRR is forecasted to be approximately 15%—over 5% less than where the RPM market has been clearing recently. From a long-term planning perspective, this reserve margin requirement difference could be significant. If the Company's forecasted load was 20,000 MW, for each percent difference between cleared reserve margin and target reserve margin, electing FRR would result in about a 200 MW reduction in purchase requirement. That said, considering the FERC MOPR Order and related filings, both the clearing price and the clearing reserve margin of the upcoming RPM forward capacity market remain highly uncertain.

An FRR election is for a minimum of five consecutive delivery years. A load serving entity ("LSE") must demonstrate its ability to meet the reserve requirement on an annual basis by committing sufficient resources to meet the reliability requirement as part its FRR plan. If an FRR plan's capacity commitment is insufficient for a delivery year, the LSE would be assessed an FRR commitment insufficiency charge for the shortage. This penalty is two times Net CONE times the MW deficiency. Capacity resources committed to an FRR plan continue to be subject to the same capacity performance requirements that apply to resources committed through the RPM forward capacity market if they are called upon in an emergency. To the extent an LSE has capacity in excess of its load requirement, those excess capacity resources may not generate the same revenue as if offered into the RPM market. The first 450 MW of excess capacity is held in reserve until the third incremental auction, with the next additional block of excess capacity up to 1,300 MW being able to offer into the RPM market auctions.

Because of its five-year minimum commitment requirement, risks to FRR election should be carefully weighed against the benefits. Risks include future environmental changes, regulatory changes, zonal constraints, and capacity and energy market changes. The potential benefits of FRR election include lower required reserve margin and the absence of MOPR risk to new generation used to meet the load obligation. All new generation would be able to be counted against the load obligation with the FRR alternative, whereas with RPM there is the likelihood that new generation would receive no capacity revenue to offset the load cost. If the Company opts out of the RPM forward capacity market through the election of the FRR alternative, it would continue to participate in PJM's energy and ancillary services markets in the same manner it does today.

The Company is continuing to evaluate the FERC MOPR Order and the FRR alternative; it has made no decision at this time. If the Company were to elect FRR, it would have to do so in advance of the next RPM base auction. Typically, this election would need to happen about six months prior to that auction; however due to the pending MOPR-related filings with FERC, the schedules may be compressed. The schedule depends on if, and when, FERC accepts PJM's recent compliance filing. PJM currently estimates the next RPM auction to occur in late 2020 or early 2021, depending on FERC's response to the PJM compliance filing.

1.7 Environmental Justice

Environmental justice is defined as 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. The Company is dedicated to meeting environmental justice expectations of fair treatment and meaningful involvement by being inclusive, understanding, and dedicated to finding solutions, and by effectively communicating with its customers and neighbors. The Company adopted an environmental justice policy in 2018 through which it committed to hearing, fully considering, and responding to the concerns of all stakeholders. This commitment includes ensuring that a voice in decisions about siting and operating energy infrastructure is given to all people and communities. Communities should have ready access to accurate information and a meaningful voice in the project development process. The Company has pledged to be a positive catalyst in its communities.

Environmental justice is also a priority for Virginia and North Carolina. In its 2020 Regular Session, the Virginia General Assembly passed multiple bills aimed at promoting environmental justice. This legislation, among other things, establishes the Virginia Council on Environmental Justice to advise the Governor on the advancement of environmental justice, and adds as a purpose of the VDEQ to further environmental justice. In addition, the Virginia Environmental Justice Act—Senate Bill No. 406 and House Bill No. 704 from the 2020 Regular Session of the Virginia General Assembly—establishes "the policy of the Commonwealth to promote environmental justice and ensure that it is carried out throughout the Commonwealth." Similarly, in North Carolina the Secretary of NCDEQ established an Environmental Justice and Equity Advisory Board to assist NCDEQ in achieving fair and equal treatment of all communities across the state. The Company is dedicated to meeting these environmental justice expectations.

1.8 New and Developing Technologies

Dominion Energy has assembled a new organization dedicated to pursuing innovative and sustainable technologies that will 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:

- **Natural Gas Combined-Cycle 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.

- **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. One example is the use of hydrogen to "co-fire" natural gas generation. Production and storage of hydrogen fuel can be one solution to the excess renewable energy that may result as increasing amounts of renewable generation resources are added to the grid.

- **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 EVs' batteries can be fed back onto the grid to lower peak demand or to provide grid support. See Section 8.6 for a discussion of the Company's Electric School Bus Program through which it seeks to explore V2G technology. A precursor to take 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. 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-Term 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. See Section 5.5.1 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 GHGs (measured in carbon dioxide equivalents ("CO_2e")) by providing for an emission reduction elsewhere. Because greenhouse gases 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.

- **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 oil field CO_2 recovery or development of synthetic fuels to provide carbon neutral transportation fuels.

- **The HAZER® Process.** The HAZER® Process converts natural gas into hydrogen and high quality graphite using iron ore as a process catalyst. The aim of the HAZER® Process is to achieve savings for the hydrogen producer, 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.

- **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 data through AMI and intelligent grid devices, and incorporates a sophisticated distributed energy resource management system.

1.9 COVID-19

At the time of filing this 2020 Plan, the world continues to confront the ongoing public health emergency related to the spread of coronavirus, also known as COVID-19. The Company's first priority is the health, safety, and well-being of its employees and communities. For its employees, the Company implemented early directives limiting travel, instituting work-from-home protocols, and expanding health and paid-time-off benefits. For its customers, the Company has suspended service disconnections for all customers, waived late payment fees for all customers, and worked to reconnect certain residential customers.

Because of the preparation schedule associated with this 2020 Plan, the Plan does not reflect any potential effects related to the COVID-19 public health emergency. PJM has published initial reports of lower demand for electricity. The Company believes it is too early to predict the long-term effects of the COVID-19 public health emergency, including the effect on customer load. The Company will continue to monitor the effects of this ongoing public health emergency and will incorporate any long-term effects as needed in future Plans and update filings.

1.10 Other Legislative Developments

In addition to the VCEA and the legislation enabling Virginia to join RGGI discussed in Sections 1.2 and 1.3, respectively, legislation was signed into law on April 11, 2020, that incorporated the relevant policy objectives into the Virginia Energy Plan—Senate Bill No. 94 and House Bill No. 714 from the 2020 Regular Session of the Virginia General Assembly. Also relevant to this 2020 Plan, House Bill 889 established a pilot program for up to 200 MW of non-residential customers load to aggregate and purchase electricity from third-party suppliers. The Company has incorporated the effects of House Bill 889 into its load forecast, as discussed in Section 4.1.4.

1.11 Other Environmental Regulations

The following section outlines changes to various environmental regulations since the Company filed its 2018 Plan. The 2018 Plan contains a historical perspective on some of the environmental regulations discussed. For a comprehensive list of relevant environmental regulations, see Section 5.2.3.

1.11.1 Affordable Clean Energy Rule

The Environmental Protection Agency ("EPA") released the final version of the Affordable Clean Energy Rule ("ACE Rule") on June 19, 2019, which replaced and repealed the Clean Power Plan. The ACE Rule was published on July 8, 2019, and applies to existing coal-fired power plants greater than or equal to 25 MW.

Under the ACE Rule, the EPA has set the best system of emissions reduction ("BSER") for existing coal-fired steam EGUs as heat rate efficiency improvements based on a range of "candidate technologies" and improved O&M practices that can be applied at the unit level. States are directed to determine which of the candidate technologies apply to each covered EGU and establish standards of performance (expressed as an emissions rate in CO_2 pounds per MWh) based on the degree of emission reduction achievable with the application of BSER. The EPA required that each state determine which of the candidate technologies apply to each coal-fired unit based on consideration of remaining useful plant life and other factors such as reasonable cost of the candidate technologies. The ACE Rule requires compliance at the unit level; it does not allow averaging across units at the same facility or between facilities as a compliance option. In addition, it does not allow states to use alternative carbon mitigation programs, such as a cap-and-trade program, to demonstrate compliance as part of their state plans. A steam generating unit that is subject to a federally-enforceable permit that limits annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less, can be excluded from the ACE Rule.

The ACE Rule requires states to develop plans by July 2022. The EPA must approve these state plans by January 2024. If states do not submit a plan or if their submitted plan is not acceptable, the EPA will have two years to develop a federal plan.

1.11.2 New Source Performance Standards for Greenhouse Gas Emissions from Electric Generating Units

The EPA issued final Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units in October 2015. In December 2018, the EPA proposed revisions to these standards that have not yet been finalized. If finalized, these standards would apply to any newly constructed or reconstructed steam generating units or stationary CTs that (i) have a base load rating over 250 million British thermal unit ("MMBtu") per hour of heat input of fossil fuel and (ii) serve a generator capable of selling greater than 25 MW of electricity to a utility power distribution system. In the proposed revisions, the EPA did not revise the performance standard for newly constructed or reconstructed natural gas combined-cycle units, which remains at the 1,000 pounds CO_2 per gross MWh standard on a 12-operating month rolling average basis. Any newly constructed or reconstructed gas turbine selling greater than 25 MW of electricity to a utility power distribution system would need to comply with the CO_2 emission standards and work practice standards required by this rule.

1.11.3 Ozone National Ambient Air Quality Standards

The ozone National Ambient Air Quality Standard ("NAAQS") governs nitrogen oxide ("NO_x") emissions. The Company has entered into a mutual shutdown agreement with VDEQ to shut down and retire Possum Point Unit 5 by June 1, 2021, because the installation and operation of selective non-catalytic reduction technology to control NO_x emissions from that unit would otherwise be needed to meet reasonably available control technology ("RACT") requirements under the 2008 ozone NAAQS of 75 parts per billion ("ppb").

The Clean Air Act ("CAA") requires the EPA to review the NAAQS every five years and revise the NAAQS if necessary. On November 22, 2019, the EPA issued a finding that seven states including Virginia failed to submit state implementation plans to satisfy the interstate report requirements of the CAA as it pertains to the 2015 eight-hour ozone NAAQS. VDEQ submitted a draft proposal to the EPA for review in early February, and is awaiting a response from the EPA prior to the VDEQ opening its draft proposal for public comment.

The EPA initiated its review of the ozone NAAQS in May 2018 and concluded in a draft policy assessment that the current NAAQS of 70 ppb is adequate. The EPA expects to finalize this policy assessment, and issue a final decision in late 2020 or early 2021.

1.11.4 Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule ("CSAPR") aims to reduce emissions of sulfur dioxide ("SO_2") and NO_x from power stations in the eastern half of the U.S. CSAPR requires certain states to reduce annual SO_2 emissions and annual ozone season NO_x emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for SO_2 and NO_x and limits the trading for emission allowances by separating affected states into two groups with no trading allowed between the groups.

While CSAPR was originally intended to help downwind states attain the 1997 ozone NAAQS, the EPA revised the emission caps downward as an update to the CSAPR in 2016 in order to aid states in meeting the 2008 ozone NAAQS (the "CSAPR Update Rule"). As a companion to the CSAPR Update Rule, the EPA issued a rule in 2018 that found that states in the program need take no additional steps to meet the 2008 ozone NAAQS beyond compliance with the existing trading program's mandates (the "CSAPR Close-Out Rule").

On September 13, 2019, the D.C. Circuit partially remanded the CSAPR Update Rule to the EPA without vacating it. The court found that the rule was inconsistent with the CAA because it did not set a deadline by which upwind states must eliminate their significant contribution to downwind states' nonattainment of the 2008 ozone NAAQS to comply with the "good neighbor" provision of the CAA. On October 1, 2019, the D.C. Circuit granted consolidated petitions for review of the CSAPR Close-Out Rule, thereby vacating and remanding the rule back to the EPA.

1.11.5 New York's Clean Air Act Section 126(b) Petition

In March 2018, the State of New York filed a petition with the EPA under Section 126 of the CAA alleging that certain stationary sources of NO_x emissions in nine states—including several EGUs in Virginia that are owned and operated by the Company—contribute to nonattainment in New York and are interfering with maintenance of the 2008 or 2015 ozone NAAQS in New York. The petition requested the EPA to impose strict NO_x limits equivalent to RACT requirements that New York has imposed on its facilities. On October 18, 2019, the EPA finalized its decision to deny the petition on the basis that New York had not demonstrated (i) that any areas in New York except for one would exceed either the 2008 or 2015 ozone NAAQS by 2023, or (ii) that the identified sources contributed to any such exceedance. On October 29, 2019, New York, New Jersey, and New York City jointly filed a petition for review in the D.C. Circuit, challenging the EPA's denial of this petition. The Company is participating as an intervenor in the litigation in support of the EPA.

On February 19, 2020, the States of New Jersey, Connecticut, Delaware, New York, and Massachusetts, along with the City of New York filed a lawsuit against the EPA in the U.S. District Court for the Southern District of New York seeking to compel the EPA to promulgate federal implementation plans for the 2008 NAAQS for ozone that fully address the requirements of the "good neighbor provision" of the CAA for seven upwind states, including Virginia.

1.11.6 Mercury & Air Toxics Standards

In February 2019, the EPA published a proposed rule to reverse its previous finding that it is appropriate and necessary to regulate toxic emissions from power plants. However, the emissions standards and other requirements of the Mercury & Air Toxics Standards ("MATS") rule would remain in place, as the EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under MATS. All of the Company's applicable units are complying with the applicable requirements of the MATS rule.

On April 16, 2020, the EPA finalized its reconsideration of its MATS supplemental cost finding and its proposed residual risk and technology review for MATS. The action was consistent with the EPA's February 2019 proposal, and rescinded the supplemental finding that had found it appropriate and necessary for the EPA to regulate mercury and hazardous air pollutant emissions from power plants. The EPA concluded that it was not appropriate and necessary to regulate hazardous air pollutant emissions from power plants under the MATS rule because the costs outweigh the benefits of emissions reductions. The EPA is also finalizing its determination that it will not be changing emissions standards for affected coal- and oil-based electric generating units. The effective date of the action will be 60 days after publication in the Federal Register. The Company expects that this action will result in litigation.

1.11.7 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 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's decision to affect its closure plans.

At the state level, in April 2018, Virginia Governor Northam signed legislation that required the Company to solicit and compile information from third parties on the suitability, cost, and market demand for beneficiation (*i.e.*, treatment of raw materials to improve chemical or physical properties) or recycling of coal ash from units at Bremo, Chesapeake, Chesterfield, and Possum Point. The coal ash recycling business plan was submitted to the Virginia General Assembly in November 2018. In March 2019, Governor Northam then signed legislation that required any CCR unit located at the Company's Bremo, Chesapeake, Chesterfield, or Possum Point power stations that stopped accepting CCR prior to July 2019 be closed by removing the CCR to an approved landfill or through recycling for beneficial reuse. The legislation further required that at least 6.8 million cubic yards of CCR be beneficially reused.

1.11.8 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 (i) to convert from wet to dry or closed cycle coal ash management, (ii) to improve existing wastewater treatment systems, and/or (iii) to 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 for these regulations remains December 2023.

In November 2019, the EPA released proposed revisions to the ELG rule that, if adopted, could extend the deadlines for compliance with certain standards at several facilities. The effects of this revised rule are still being evaluated and studies are currently underway to determine the best path for compliance.

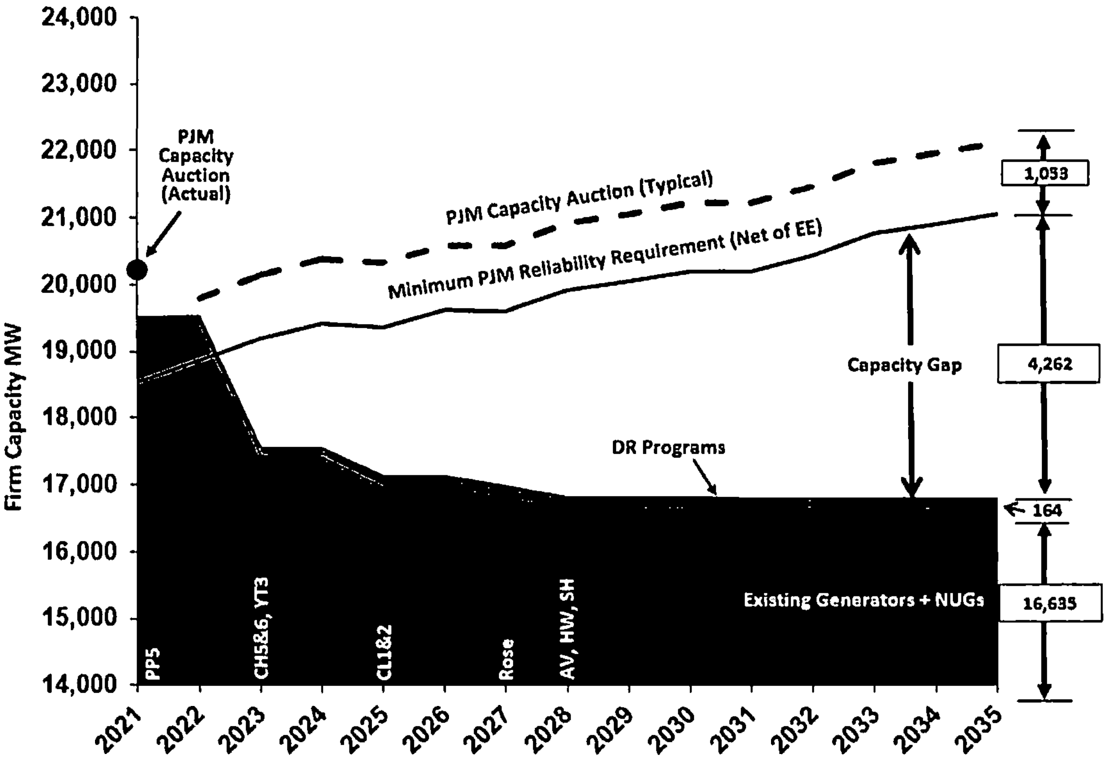
Chapter 2: Results of Integrated Planning Process

This chapter presents the results of the integrated planning process, including the Company's current capacity and energy positions, the Alternative Plans presented to meet the future capacity and energy needs of the Company's customers, and the net present value ("NPV") of each Alternative Plan. This section also includes the results of the initial transmission system reliability analysis related to the retirement of all Company-owned carbon-emitting generation in 2045, and the results of a Virginia residential bill analysis.

2.1 Capacity and Energy Positions

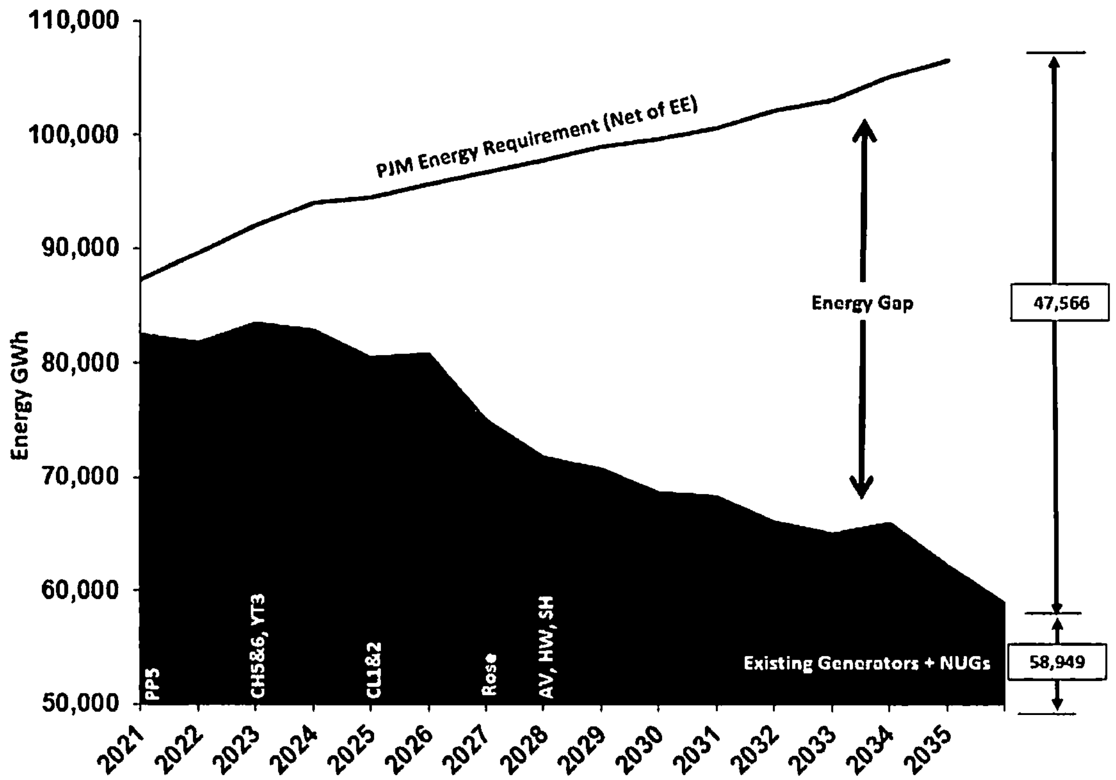
Figures 2.1.1 and 2.1.2 illustrate the Company's current capacity and energy positions using unit retirement assumptions for Alternative Plan B. After adjusting for energy efficiency, voltage optimization, and retail choice as discussed in Sections 4.1.3, 4.1.4, and 4.1.5, respectively, DOM LSE is expected to experience a compound annual growth rate ("CAGR") of 1.0% in future summer peak demand and 1.3% in energy requirements over the Planning Period.

Figure 2.1.1 - Current Company Capacity Position (2021 to 2035)



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.1.2 - Current Company Energy Position (2021 to 2035)



Notes: "Existing Generators + NUGS" include generation under construction; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

2.2 Alternative Plans

The 2020 Plan presents a range of alternatives representing paths forward for the Company to meet the future capacity and energy needs of its customers. Notably, however, the build plans shown in Alternative Plans B through D do not fully account for possible system reliability and security issues. More planning work is 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 and achieve its clean energy goals while protecting customers from a variety of potential challenges.

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

- Plan A – This Alternative Plan presents a least-cost plan that estimates future generation expansion where there are no new constraints, including no new regulations or restrictions on CO_2 emissions. Plan A is presented for cost comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, this Alternative Plan does not represent a realistic state of relevant law and regulation.

- Plan B – This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues.

- Plan C – This Alternative Plan uses similar assumptions as Plan B, but retires all Company-owned carbon-emitting generation in 2045, resulting in close to zero CO_2 emissions from the Company's fleet in 2045. To reach zero CO_2 emissions in 2045, Plan C significantly increases the amount of energy storage resources and the level of imported power.

- Plan D – This Alternative Plan uses similar assumptions as Plan C, but changes the capacity factor assumption for future solar resources from 25% to 19%. As a result, Plan D significantly increases the amount of solar resources needed to reach zero CO_2 emissions in 2045.

Figures 2.2.1 through 2.2.4 show the build plans for each Alternative Plan. See Appendix 2A for the capacity and energy associated with all Alternative Plans.

Figure 2.2.1 - Alternative Plan A (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired	Nuclear	Retirements
2021									PP5
2022		480							
2023		480					485		YT3, CH5&6
2024		480					485		
2025		480					485		CL1&2
2026		480					485		
2027		480							Rosemary
2028		480							
2029		480							
2030		480							
2031		480							
2032		480						Surry 1	
2033		480						Surry 2	
2034		480							
2035		480							
TOTAL	0	6,720	0	0	0	0	1,940	1,676	3,030

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal).

Figure 2.2.2 - Alternative Plan B (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	600	360	220	852	400				
2027	600	360		1,704	500				Rosemary
2028	600	480	220						AV, HW, SH
2029	960	480			500				
2030	960	360	220			300			
2031	720	360							
2032	720	360			500			Surry 1	
2033	720	360						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	9,660	5,160	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.2.3 - Alternative Plan C (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	600	360	220	852	400				
2027	600	360		1,704	500				Rosemary
2028	600	480	220						AV, HW, SH
2029	960	480			500				
2030	960	360	220			300			
2031	720	360							
2032	720	360			500			Surry 1	
2033	720	360						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	9,660	5,160	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.2.4 - Alternative Plan D (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	960	360	220	852	400				
2027	960	480		1,704	500				Rosemary
2028	960	480	220						AV, HW, SH
2029	960	480			500				
2030	960	600	220			300			
2031	960	600							
2032	960	600			500			Surry 1	
2033	960	600						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	11,460	6,240	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Alternative Plans B, C, and D include 970 MW of natural gas-fired CTs as a placeholder to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

Figure 2.2.5 shows the CO_2 emissions from the Company's fleet for each Alternative Plan, while Figure 2.2.6 shows the regional CO_2 emissions for each Alternative Plan. Because the regional CO_2 emissions capture the effects of both energy imports and exports required to meet customer needs, the regional emissions are a better indicator of customers' impact on the environment.

Figure 2.2.5 – Virginia CO_2 Output from Company Fleet for Alternative Plans

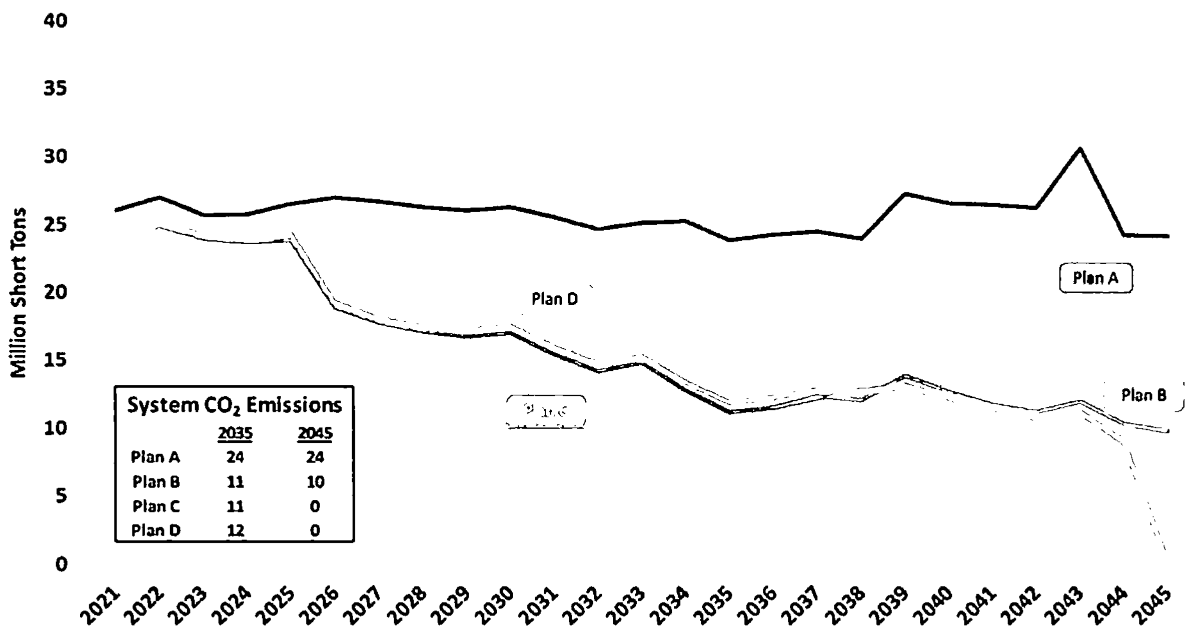
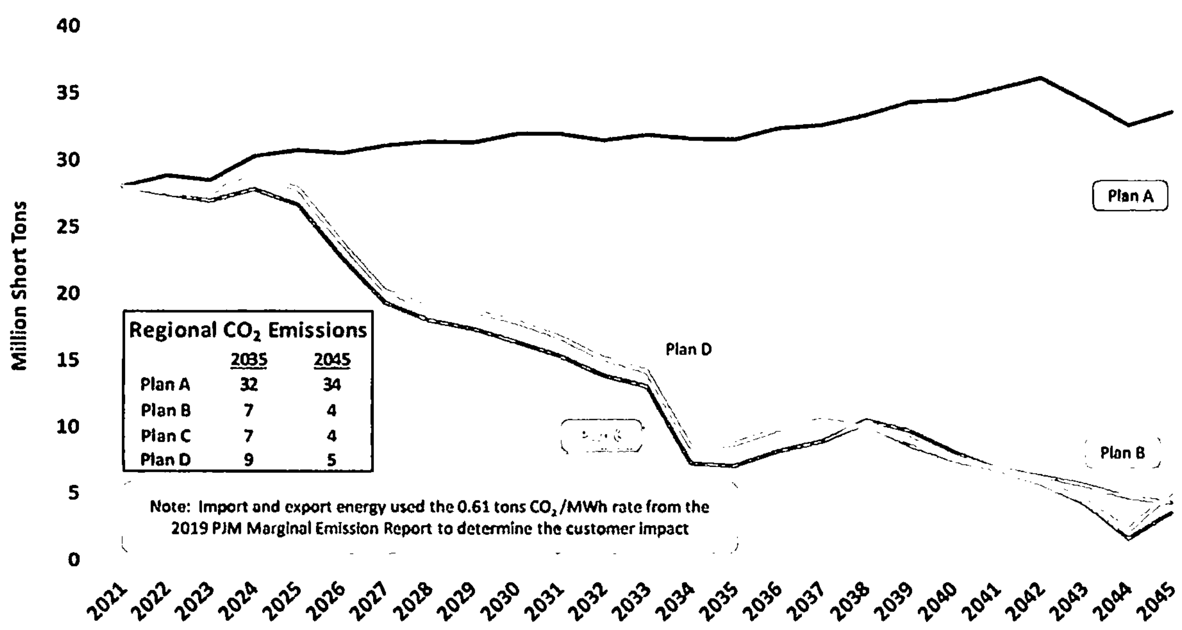


Figure 2.2.6 – Regional CO_2 Output for Alternative Plans



As seen in Figures 2.2.2 through 2.2.4, Plans B through D are all very similar over the first 15 years of each Alternative Plan. This alignment between Alternative Plans B through D over the 15-year Planning Period creates a common pathway for the Company to pursue now while allowing new technologies to emerge and mature, and allowing analysis and study to continue. Accordingly, for this 2020 Plan, the Company recommends a path forward that substantially aligns with the first 15 years of Alternative Plans B through D. Over the longer-term, however, based on current technology and this "snapshot in time," the Company recommends Alternative Plan B.

2.3 Transmission System Reliability Analysis

In order to understand the possible transmission system reliability implications of retiring all Company-owned carbon-emitting generation in 2045, as contemplated by Alternative Plans C and D, the Company performed a transmission system power flow analysis by developing a base power flow case and three different scenarios, and utilizing simplifying assumptions. The initial results of this analysis identified North America Electric Reliability Corporation ("NERC") reliability deficiencies on twenty-six 115 kV lines, thirty-two 230 kV lines, six 500 kV lines, and eleven transmission transformers that would need to be resolved to avoid NERC violations. In addition, the results indicated that Alternative Plans C and D would require construction of four interstate transmission lines at an estimated cost of $8.4 billion. A discussion of this analysis and the full results are provided in Section 7.5.

2.4 NPV Results

The Company evaluated the Alternative Plans to compare and contrast 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

2020 $B	Plan A	Plan B	Plan C	Plan D
Total System Costs[1]	$ 34.7	$ 56.8	$ 60.7	$ 63.0
GT Plan	$ 0.2	$ 3.2	$ 3.2	$ 3.2
SUP	$ 2.2	$ 2.2	$ 2.2	$ 2.2
Broadband	$ -	$ 0.2	$ 0.2	$ 0.2
Transmission Underground Pilot	$ -	$ 0.2	$ 0.2	$ 0.2
Transmission	$ 5.1	$ 5.1	$ 5.1	$ 5.1
Transmission Level Import Increase	$ -	$ -	$ 8.4	$ 8.4
Customer Growth	$ 2.0	$ 2.0	$ 2.0	$ 2.0
Subtotal Plan NPV[2]	**$ 44.3**	**$ 69.7**	**$ 82.1**	**$ 84.3**
Less Benefits of GT Plan	$ -	$ (3.5)	$ (3.5)	$ (3.5)
Total Plan NPV	**$ 44.3**	**$ 66.2**	**$ 78.6**	**$ 80.8**
Plan Delta vs. Plan A	**$ -**	**$ 21.9**	**$ 34.3**	**$ 36.6**

Notes: (1) Total system costs include the results from Figures 2.2.1 through 2.2.4 plus approved, proposed, and generic DSM; solar interconnection costs; and solar integration costs. (2) Numbers may not add due to rounding.

2.5 Virginia Residential Bill Analysis

The bill of a typical residential customer in Virginia using 1,000 kWh per month as of December 31, 2019, was $122.66. As of May 1, 2020, this typical bill is $116.18, largely attributable to a significant decrease in the fuel factor. The Company calculated the projected residential bill for Alternative Plans A and B over each of the next ten years. Figure 2.5.1 presents the summary results of these projections in 2030, as well as the CAGR. Importantly, these bill projections are not final—all Company rates are subject to regulatory approval. Additionally, the bill projection associated with Alternative Plan A is presented for comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, Plan A does not represent a realistic state of relevant law and regulation.

As can be seen in Figure 2.5.1, about 40% of the projected bill increase from 2020 to 2030 is associated with investments incentivized or mandated by the VCEA and other legislation from the 2020 Regular Session of the Virginia General Assembly. Roughly one-third is attributable to compliance with directives that pre-date 2020, including the GTSA. Overall, the projected bill increase is approximately 2.9% on a compound annual basis using year-end 2019 customer bill as a baseline. The Company used year-end 2019 for this calculation to compare full-year data points. For comparison, in 2008, the year following passage of the Virginia Electric Utility Regulation Act, the bill of a typical residential customer in Virginia using 1,000 kWh per month was $107.20. Using 2008 as a baseline, the projected compound annual growth rate in the typical residential customer bill through 2030 is approximately 2.1%.

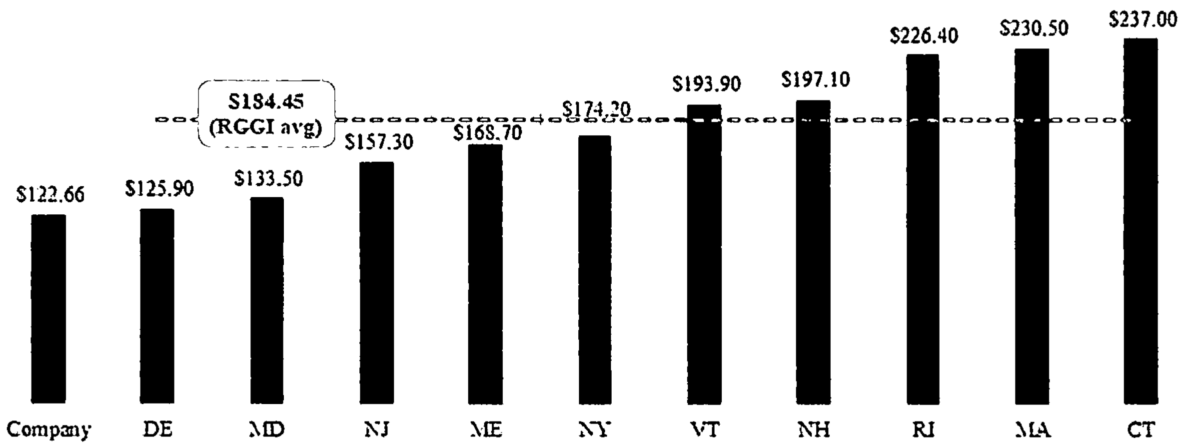
Figure 2.5.1 – Residential Bill Projection (1,000 kWh per Month)

	2030	CAGR
2019 Year End	$122.66	
Plan A[1]	$11.70	0.8%
Pre-2020 Legislation[2]	$15.28	1.0%
2020 Legislation[3]	$18.94	1.1%
Total 2030 Year End	**$168.58**	**2.9%**
Total Bill Increase	$45.92	

Notes: (1) Represents bill projections associated with future generation in Alternative Plan A; approved and proposed investments in DSM; approved investments in the Grid Transformation Plan (*i.e.* Phase IA and IB); investments in the Strategic Underground Program; and compliance with environmental laws and regulations, including CCR investments. (2) Represents bill projections associated with future generation in Alternative Plan B and other investments incentivized or mandated by legislation prior to 2020, including legislation related to pumped storage (2017), the GTSA (2018), and rural broadband (2019). (3) Represents bill projections associated with future generation in Alternative Plan B and other investments incentivized or mandated by the VCEA and other 2020 legislation.

For perspective, the average residential rate for RGGI states normalized for 1,000 kWh monthly usage—approximately $184.45—is approximately 50% higher than the Company's typical residential bill as of year-end 2019 (*i.e.*, $122.66). See Figure 2.5.2.

Figure 2.5.2 – Residential Bill Comparison for RGGI States[1]



Note: (1) Based on residential rate data for RGGI states from U.S. Energy Information Administration as of February 2020, normalized for 1,000 kilowatt-hour monthly usage. Typical 1,000 kilowatt-hour residential bill for Company as of year-end 2019.

<u>Chapter 3: Short-Term Action Plan</u>

The short-term action plan provides the Company's strategic plan for the next five years (2020 to 2025). Generally, 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 and reliable service to its customers. As shown in Figures 2.2.2 through 2.2.4, Alternative Plans B through D present the same path forward in the next five years, and substantially similar paths over the next 15 years.

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 RPS requirements established by the VCEA, including related requests for approval of certificates of public convenience and necessity and for prudence determinations related to PPAs;
- Continue the construction of the CVOW demonstration project;
- Continue development and begin construction of a larger build-out of offshore wind off the coast of Virginia;
- Meet its targets under the Virginia RPS at a reasonable cost and in a prudent manner by: (i) applying renewable energy from existing generating facilities, including NUGs; (ii) constructing and operating new renewable energy facilities and energy storage facilities; (iii) purchasing cost-effective RECs, including optimizing RECs produced by Company-owned generation (*i.e.*, when higher priced RECs are sold into the market and less expensive RECs are purchased and applied to the Company's RPS requirements);
- Meet its target under North Carolina Renewable Energy Portfolio Standard at a reasonable cost and in a prudent manner, and submit its annual compliance report and compliance plan;
- Support ongoing Nuclear Regulatory Commission ("NRC") review of the subsequent license renewal application submitted for Surry Units 1 and 2 in October 2018;
- Submit an application to the NRC for the subsequent license renewal for North Anna Units 1 and 2 by the end of 2020;
- Continue developmental work for 300 MW of new pumped hydroelectric storage in southwestern Virginia;
- Achieve a minimum of 10% electricity production at VCHEC through the use of renewable waste wood by the end of 2021;
- Continue to make investments at existing generation units needed to comply with environmental regulations;
- In order to preserve the option to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities in the near term, evaluate sites and equipment for the construction of gas-fired CT units;

- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements; and
- Enhance access to natural gas supplies, including shale gas supplies from multiple supply basins.

Appendices 3A and 3B provide further details on each generation project under construction and under development, respectively. Appendix 3C provides a comparison of the short-term action plan for generation resources in this 2020 Plan compared to the 2018 Plan.

3.2 Demand-Side Management

Over the next five years, the Company will continue to identify and propose new or revised DSM programs that meet the existing requirements of the GTSA and the new requirements and targets in the VCEA in conjunction with the DSM stakeholder process. The Company also expects to complete a new market potential study in late 2020, and will work with stakeholders through the existing stakeholder processes towards development of a long-term strategy to achieve legislative requirements in both the GTSA and VCEA as they relate to energy efficiency.

In Virginia, the Company filed its Phase VIII DSM application in December 2019 seeking approval of 11 DSM programs and an extension of one existing program. The SCC must issue its final order on this application by August 2020.

In North Carolina, the Company will continue its analysis of future programs and will file for approval in North Carolina for those programs that have been approved in Virginia that continue to meet Company requirements for new DSM resources. For programs that are not approved by the SCC, the Company will evaluate the programs on a North Carolina-only basis.

3.3 Transmission

Over the next five years, the Company will continue to assess its transmission system and to construct facilities required to meet the needs of its customers. Generally, the Company anticipates transmission projects that are needed to rebuild aging infrastructure and to interconnect data center customers. The Company also intends to pursue an additional underground transmission line project under the pilot program established by the GTSA as modified by House Bill No. 576 from the 2020 Regular Session of the Virginia General Assembly, which was signed into law on March 4, 2020. Appendix 3D provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM.

The Company will also explore options to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities. Finally, the Company will continue its long-term analysis of the actions and costs associated with the retirement of dispatchable carbon-emitting generating units and the integration of large volumes of intermittent renewable generation on the transmission system.

3.4 Distribution

Over the next five years, the Company will continue to assess its distribution system, 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 system:

- Implement the Grid Transformation Plan, including initiatives to facilitate the integration of DERs, enhance grid reliability and security, and improve the customer experience;
- Publish hosting capacity maps for both utility scale and net metering DERs;
- Continue to develop integrated distribution planning capabilities, including a standardized screening process to consider non-wires alternatives for distribution grid support;
- Continue its Strategic Undergrounding Program ("SUP");
- Pilot V2G technology through the Electric School Bus Program;
- Pilot BESS as grid support resources; and
- Participate in the rural broadband pilot program.

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 supply-side resources to determine the economic feasibility of those resources. Next, a feasibility screening, followed by a busbar screening curve analysis, 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 load, 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 VCEA). 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 utility 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 2020 Plan does not incorporate sub-hourly analysis because the Company is still developing the inputs required for such an analysis. Sub-hourly analysis will require sub-hourly inputs based on historical performance for all resource type that could represent the operating characteristics of those resource 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. Nevertheless, the Company intends to incorporate sub-hourly analysis in future Plans and update filings once the required inputs and processes are developed and validated. This 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 2020 Plan, the Company relies on several assumptions for its integrated resource planning process. This chapter discusses these assumptions related to load forecast, capacity needs, capacity value, commodity prices, RPS, solar, storage, gas transportation, the least-cost plan, and the VCEA. The Company updates its assumptions annually to maintain a current view of relevant markets, the economy, and regulatory drivers.

4.1 Load Forecast

The 2020 Plan presents two load forecasts: (i) the 2020 PJM Load Forecast and (ii) the 2020 Company Load Forecast. The 2020 PJM Load Forecast was used in the development of all Alternative Plans. Because of the limited nature of the information provided by PJM, however, the Company presents and discusses the 2020 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. To provide an apples-to-apples comparison of peak load, the Company added back behind-the-meter generation resources to the PJM Load Forecast.

Overall, the PJM Load Forecast anticipates summer peak demand and energy CAGR for the Dominion Energy Zone ("DOM Zone") of approximately 1.0% and 1.3%, respectively, over the Planning Period. The Company's Load Forecast anticipates DOM Zone summer peak demand and energy forecast CAGR of 1.2% and 1.4%, respectively.

Figure 4.1.1 - DOM Zone Peak Load Comparison

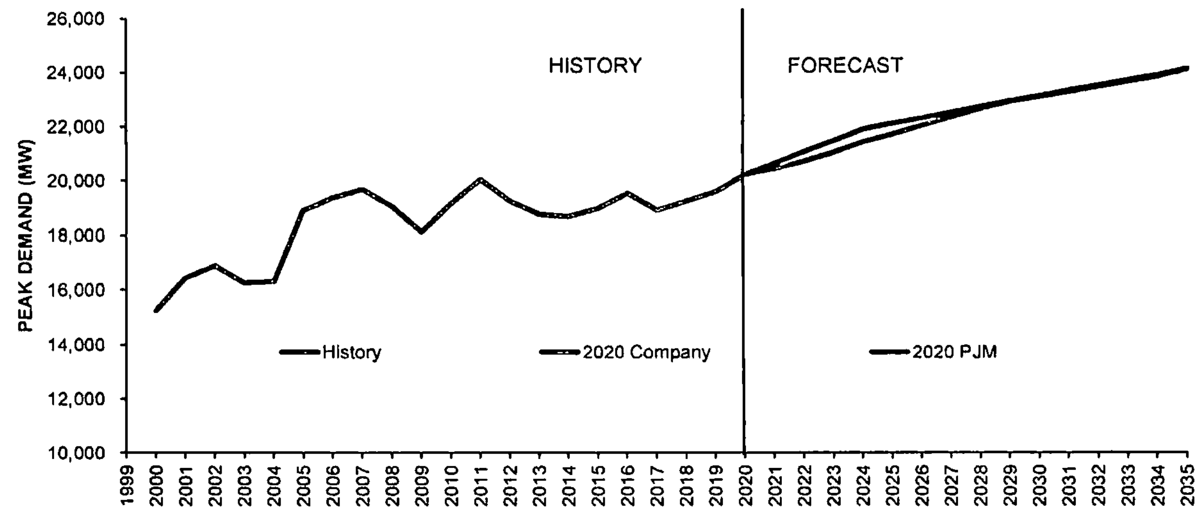
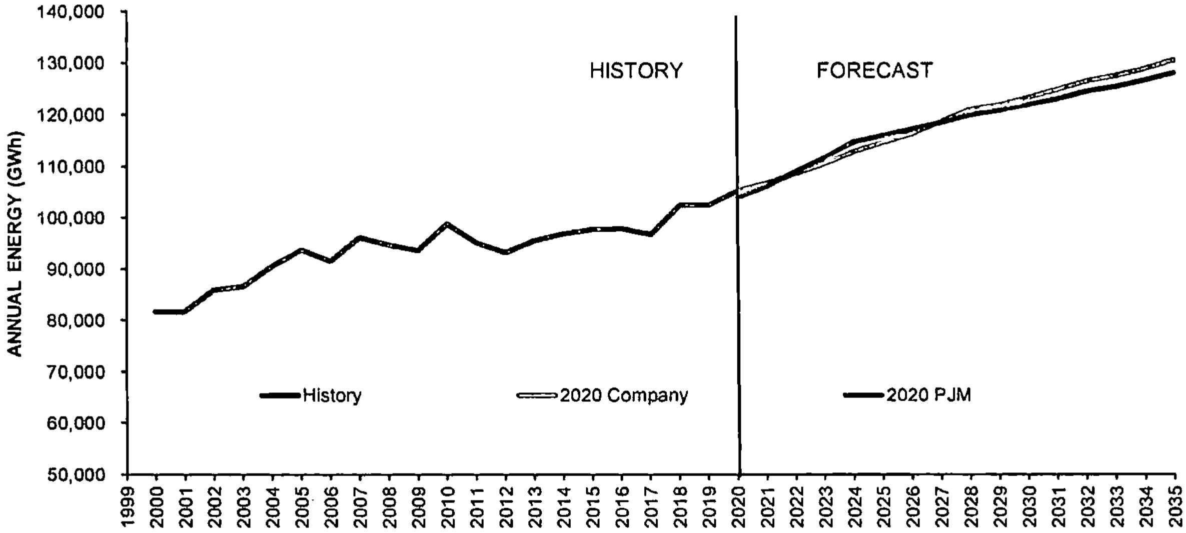


Figure 4.1.2 - DOM Zone Annual Energy Comparison



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 and 15-year projected load for wholesale customers are provided in Appendix 4K. See Appendix 4L for load duration curves for the years 2020, 2025, and 2035 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.

Notably, neither the 2020 PJM Load Forecast nor the Company Load Forecast incorporates any effects on load of the ongoing public health emergency related to the spread of COVID-19.

4.1.1 PJM Load Forecast

The Company utilized the DOM Zone load forecast as published by PJM in its 2020 PJM Load Forecast Report dated January 2020 in the development of Alternative Plans A through D included in this 2020 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 2020 Plan, the Company needed to adjust that forecast for modeling purposes. Because the PJM Load Forecast only provides a 15-year forecast, PJM's 15-year CAGR of 1.0% and 1.3% was used to extend the summer peak demand and energy forecasts, respectively, for years 2035 through 2045. Since PJM does not provide a DOM LSE forecast, the Company then scaled down the PJM DOM Zone coincident peak load forecast and energy forecast. This required the Company to adjust PJM's DOM Zone forecasts by a percentage factor calculated using a regression technique that utilized historical peak and energy data over the preceding 10-year period. Figure 4.1.1.1 presents the forecast extension and the DOM Zone adjustment.

Figure 4.1.1.1 – 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)
2021	19,486	16,802	104,845	90,435
2022	19,837	17,105	107,471	92,700
2023	20,178	17,339	110,012	94,893
2024	20,462	17,644	112,951	97,428
2025	20,651	17,807	114,053	98,378
2026	20,880	18,004	115,176	99,347
2027	21,072	18,170	116,343	100,353
2028	21,250	18,323	117,880	101,679
2029	21,404	18,456	118,745	102,426
2030	21,572	18,601	119,722	103,269
2031	21,756	18,759	120,756	104,160
2032	22,008	18,977	122,161	105,372
2033	22,176	19,121	122,831	105,950
2034	22,326	19,251	123,897	106,870
2035	22,249	19,357	125,114	107,920
2036	22,686	19,561	126,752	109,333
2037	22,926	19,768	128,412	110,765
2038	23,168	19,977	130,093	112,215
2039	23,413	20,188	131,797	113,685
2040	23,661	20,402	133,522	115,174
2041	23,911	20,617	135,270	116,682
2042	24,163	20,835	137,042	118,210
2043	24,419	21,055	138,836	119,758
2044	24,677	21,278	140,654	121,326
2045	24,938	21,503	142,495	122,915

Next, the Company needed to adjust the PJM Load Forecast to properly incorporate it into PLEXOS. Planning models, including PLEXOS, require 8,760-hour (*i.e.*, the total hours in a year) load shapes ("8,760 load shapes") as a necessary input. PJM does not provide forecasted 8,760 load shapes. Instead of attempting to generate 8,760 load shapes for PJM, the Company adjusted a historical DOM LSE summer peak 8,760 load shape to meet the annual coincident peak demand and energy derived from the 2020 PJM DOM Zone Load Forecast.

PJM's practice is to adjust their load forecasts downward for current and forecasted DERs, which includes a forecast for net metering customers. Given this practice, all PLEXOS modeling that utilized the PJM Load Forecast in this 2020 Plan excluded DERs (including net metering customers) from the supply options.

One final note regarding the 2020 PJM Load Forecast is that PJM developed several revisions to its load forecasting process in 2019. Because of those changes, PJM now considers the DOM Zone to be a winter peaking zone. In other words, the winter peak demand forecast for the DOM Zone now exceeds the summer demand peak in all years of the forecast period according to PJM.

Given that the PJM RTO is still a summer peaking entity, however, PJM will still procure capacity for the DOM Zone at levels commensurate with the DOM Zone coincident summer peak forecast. As such, the Company developed this 2020 Plan using a summer peak 8,760 shape modified to align with PJM's DOM Zone summer coincident peak demand and energy forecast.

4.1.2 Company Load Forecast

This 2020 Plan also includes the Company's internally developed peak demand and energy forecast. The Company ran a sensitivity on Alternative Plan B, re-optimizing the build plan based on use of this internally developed forecast instead of the PJM Load Forecast. Figure 4.1.2.1 displays the results of this sensitivity analysis.

Figure 4.1.2.1 - Load Forecast Sensitivity

	Plan B	**Plan B Load Forecast Sensitivity**
Load Forecast	PJM	Company
NPV Total	$66.2 B	$66.8 B
Solar (MW)	15,920 15-year 31,400 25-year	15,920 15-year 31,400 25-year
Offshore Wind (MW)	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year
Storage (MW)	2,714 15-year 5,114 25-year	2,714 15-year 5,114 25-year
Combustion Turbine (MW	970 15-year 970 25-year	970 15-year 970 25-year
PJM Imports (MW)	5,200 15-year 5,200 25-year	5,200 15-year 5,200 25-year
Retirements (MW	3,183 15-year 5,414 25-year	3,183 15-year 5,414 25-year

As can be seen, the Company Load Forecast produces the same build plan as the PJM Load Forecast, all other Plan B assumptions being equal. The NPV is slightly higher using the Company Load Forecast because the Company would need to purchase additional energy in the later years of the Study Period. These results confirm that the two forecasts are very similar. In addition, it shows that the main driver for the units selected in the build plan for Alternative Plan B was the requirements of the VCEA, not the load forecast.

The following paragraphs describe the Company's internal load forecasting process, plus the new revisions to that process that were incorporated since the 2018 Plan was published.

Methodology

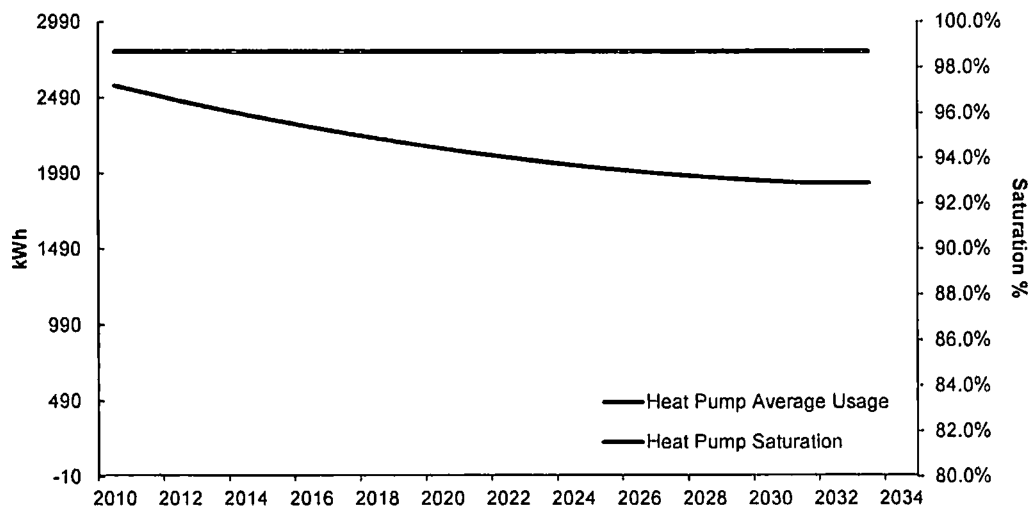
The Company uses two econometric models with an end-use orientation to forecast sales, energy, and peak demand. The first is a customer class level sales model ("Sales Model") and the second is a system level hourly load model ("Peak and Energy Model"). The models used to produce the Company Load Forecast have been developed, enhanced, and re-estimated annually for over 20 years. Both models were estimated over a rolling 15-year historical period as each long-term forecast is developed.

Sales Model

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, as well as other LSEs in the DOM Zone (all of which are in the PJM RTO). The monthly sales equations are specified in a manner that produces estimates of heating load, cooling load, and non-weather sensitive load. In addition to developing a sales forecast, the primary role of the Sales Model is to provide estimates of historical and projected weather sensitive appliance stocks and non-weather sensitive base demand for use as exogenous variables in the Peak and Energy Model.

The residential sales equation also relies on an algorithm that dynamically adjusts forecasted appliance saturation and usage based on historical trends. These historical trends are determined from appliance data collected through surveys of the Company's residential customers. Figure 4.1.2.2 shows historical and forecasted saturation and usage data for residential heat pumps.

Figure 4.1.2.2 – Residential Heat Pump (Cooling) Saturation and Usage



The next residential and commercial customer appliance survey and subsequent conditional demand analysis will be completed in the second half of 2020.

The Company has performed out-of-sample testing on its Sales Model for the residential, commercial, industrial, and public authority (government) customer classes. The results of tests are included in the Company's load forecasting model documentation.

Peak and Energy Model

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

The Peak and Energy 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 and Energy Model also employs indicator variables to capture monthly, day of week, time of day, holiday, and other seasonal effects, as well as unusual events such as hurricanes that produce widespread outages.

The forecast of expected DOM Zone monthly and seasonal peaks and energy output is produced by simulating hourly demands from the estimated Peak and Energy Model over actual hourly weather from each of the past 15 years under projected economic conditions. The final forecasted zonal peak and energy values include subsequent adjustments for projected data centers, EVs, or other significant load additions not reflected in the hourly regression equations.

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

Data Center Forecast

Data center sales, energy, and peak demand are now being forecasted by the Company as a standalone category and are being applied to the Company's sales, peak, and energy forecasts as an exogenous adjustment. This action is consistent with a forecasting recommendation provided by Itron Inc. ("Itron"), as discussed below. Figures 4.1.2.3 and 4.1.2.4 reflect the data center peak and energy forecast, respectively.

Figure 4.1.2.3 – Data Center Peak Demand Forecast

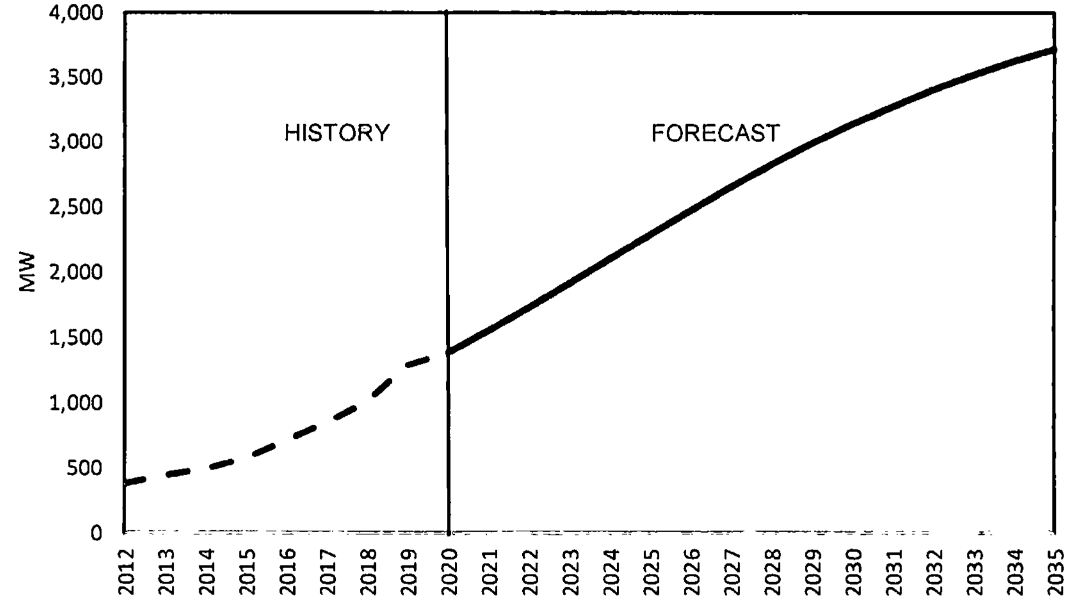
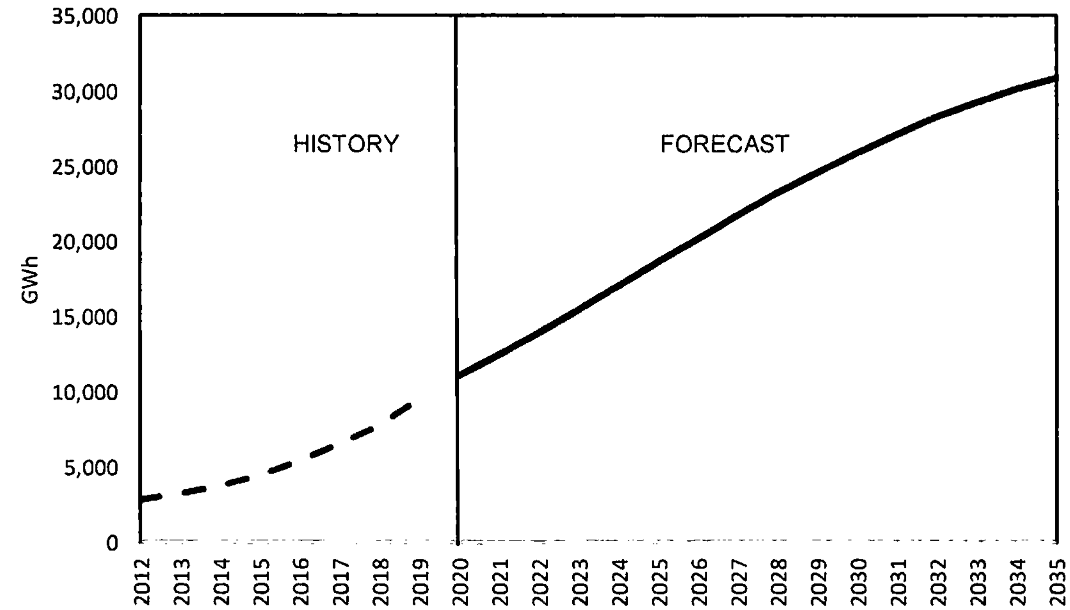


Figure 4.1.2.4 – Data Center Energy Forecast



Electric Vehicle Forecast

The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load. For this 2020 Plan, the Company has revised its EV forecasting process. Like data centers, the Company now subtracts EV sales from history and re-estimates the residential and commercial sales models. Also, like data centers, a separate EV forecast is developed and added to the appropriate residential or commercial sales forecast as a model post-

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processing adjustment. The EV forecast was developed by Navigant Consulting, Inc. ("Navigant"). The Company used this same EV forecast to develop the recently-approved Smart Charging Infrastructure Pilot Program, a component of its Grid Transformation Plan discussed further in Section 8.3. The only modification to the Navigant forecast was that the Company extended the forecast from 10 years to 25 years using the same long-term growth rates calculated from the forecast itself. Figures 4.1.2.5 and 4.1.2.6 reflect the EV peak and energy forecast, respectively.

Figure 4.1.2.5 – Electric Vehicle Peak Demand Forecast

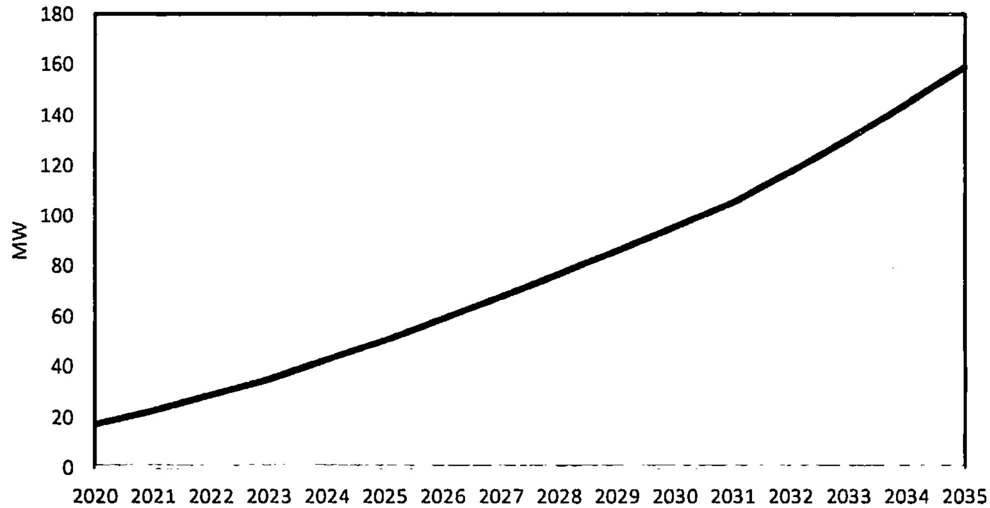
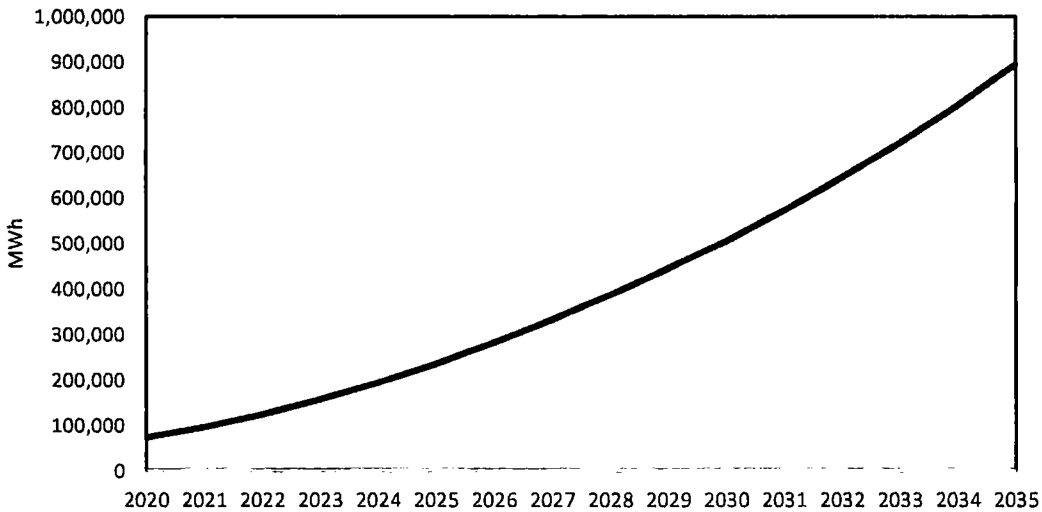


Figure 4.1.2.6 – Electric Vehicle Energy Forecast



Independent Review of the Company's Load Forecasting Process

In response to feedback received during the 2018 Plan proceeding, the Company engaged Itron in 2019 to (i) review its load forecasting process and methods and (ii) perform a long term (*i.e.*, greater than 5 years) study of data center growth within the Company's service territory. Overall, Itron concluded that the Company's load forecast methodology provides reasonable projections for long-term resource planning, and offered general recommendations that could improve that approach. The Company has incorporated the following load forecast recommendations into this 2020 Plan:

- Itron recommended that the Company shorten the coefficient estimation period from the Company's traditional period of 30 years. Consistent with this recommendation, the 2020 Company Load Forecast utilized 15 years of history to re-estimate the model and also used 15 years of weather history in its weather normalization process.
- Itron recommended that the Company isolate the data center loads from commercial sales and system hourly loads. Consistent with this recommendation, the 2020 Company Load Forecast removed the data center peak demand and energy from the commercial sector and estimated each sector (*i.e.*, non-data center commercial and data centers) independently.

The Company will continue to review the results of the Itron study and incorporate recommendations into its load forecasting process as appropriate.

Itron also made several findings regarding long-term data center growth, including:

- With continuing demand growth for offsite computing and cloud-based computer service, strong Northern Virginia data center demand is expected to grow well into the future;
- Data center demand is expected to increase 176 MW on average per year between 2020 and 2030; and
- Utilizing the Bass Diffusion Model is a reasonable approach to forecasting long-term data center growth.

Economic and Demographic Assumptions

The economic and demographic assumptions that were used in the Company Load Forecast models were supplied by Moody's Analytics, prepared in October 2019, and are included as Appendix 4M. Figure 4.1.2.7 summarizes the economic variables used to develop the Company's sales and peak load forecasts.

Figure 4.1.2.7 - Major Assumptions for the Sales and Peak and Energy Models

	2020	2035	Compound Annual Growth Rate (%) 2020 - 2035
DEMOGRAPHIC:			
Customers (000)			
Residential	2,373	2,754	1.00%
Commercial	247	279	0.81%
Population (000)	8,627	9,341	0.53%
ECONOMIC:			
Employment (000)			
State & Local Government	545	616	0.82%
Manufacturing	244	202	-1.25%
Government	728	800	0.63%
Income ($)			
Per Capita Real disposable	47,758	62,345	1.79%
Price Index			
Consumer Price (1982-84=100)	261	368	2.33%
VA Gross State Product (GSP)	497	659	1.90%

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 for the DOM Zone. The supplier of these explanatory variable forecasts for the 2020 Company Load Forecast was Moody's Analytics ("Moody's"); PJM also used explanatory variables from Moody's in the development of its 2020 Load Forecast.

In past proceedings, questions have arisen about the use of Moody's and whether other entities could provide such forecasts. To the Company's knowledge, the only other reputable supplier of these forecast variables is IHS Markit ("IHS"). For direct comparison purposes in this 2020 Plan, the Company procured Virginia economic variable forecasts from both Moody's and IHS. Appendix 4N provides charts comparing different relevant variables. As shown in Appendix 4N, except for housing permits, IHS forecasts are similar to or higher than Moody's. The Company uses the housing permit forecast as an input variable in its residential load forecasting process to determine the number of residential customers. The residential load forecast also incorporates other input variables, such as disposable income forecast. If the Company had used IHS's economic variable forecasts instead of Moody's, it is likely that the residential sales results would be similar because while IHS's housing permit forecast is lower than Moody's, IHS's disposable income forecast is higher.

Net Metering Forecast

The Company has developed a process that can forecast residential and commercial net metering customers on a feeder level basis. This forecasting method can be used by the Company in forecasting future net metering supply-side resources. It cannot be used when using the PJM Load Forecast because PJM calculates behind-the-meter (including net metering) resources using different methods and reduces its overall load forecast by the determined values.

The net metering forecast process is composed of two components. The first component is the three parameter Bass Diffusion Model ("BDM") and the second component is a logit classification model. On a feeder level basis, the BDM is fit to actual net metering customer data to determine the first two parameters of the BDM, which are the coefficient of innovation and the coefficient of imitation. The logit classification model is used to determine the maximum number of potential customers that will elect to implement net metering technology at their premises using demographic information such as premises size, age, and value. This maximum number of potential customers figure is then utilized within the BDM framework as the third parameter to determine the leveling off point or the 100% saturation level of the BDM. This process will determine the net metering customer forecast, which is then translated into kWh using feeder averages for single unit size and capacity factor. The methods should prove valuable as the Company's distribution planners proceed with feeder assessments as part of evolving integrated distribution planning capabilities.

Wholesale Power Sales

The Company currently provides full requirement wholesale power sales to three entities, which are included in the Company Load Forecast. Appendix 4K provides a list of wholesale power sales contracts with parties to whom the Company has either committed or expects to sell power during the Planning Period.

Results

The DOM Zone is typically a summer peaking system. The all-time summer unrestricted peak demand for the DOM Zone is 20,328 MW and was set in the summer of 2011. On July 20, 2019, the DOM Zone unrestricted peak demand was 20,161 MW. The peak-producing weather event that drove this 2019 summer demand culminated on a Saturday. The Company estimates that had this weather pattern culminated on a weekday, the load would have been approximately 500 MW higher, thus resulting in a new all-time summer peak demand of 20,661 MW. However, during the winter periods of 2013/2014, 2014/2015, 2017/2018, and 2018/2019, significant DOM Zone unrestricted peaks were set at 19,978 MW, 21,867 MW, 21,350 MW, and 20,104 MW, respectively. Nevertheless, based on its load forecasting process—and unlike PJM—the Company still considers the DOM Zone to be a summer-peaking zone through 2031.

The historical DOM Zone summer peak growth rate has averaged about 1.3% annually over the 2004 to 2019 period. The annual average energy growth rate over the same period is approximately 0.8%. Historical DOM Zone peak load and annual energy output along with a 15-year forecast are shown in Figures 4.1.2.8 and 4.1.2.9. Figure 4.1.2.8 also reflects the actual winter peak demand. DOM LSE peak and energy requirements are both estimated to grow annually at an approximate CAGR of 1.3% and 1.4%, respectively, throughout the Planning Period.

Figure 4.1.2.8 – DOM Zone Peak Load Based on Company Load Forecast

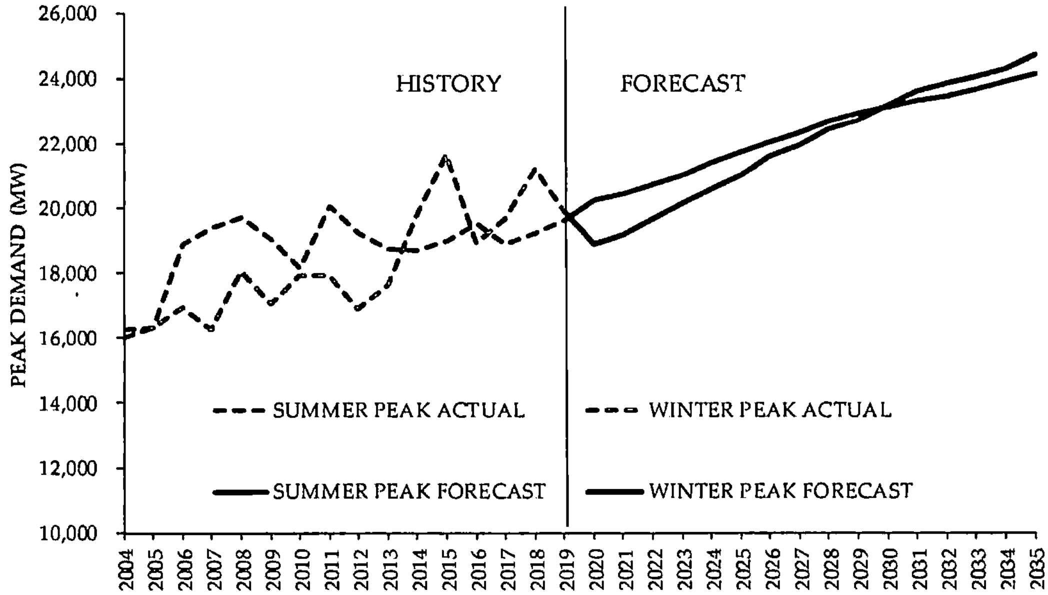
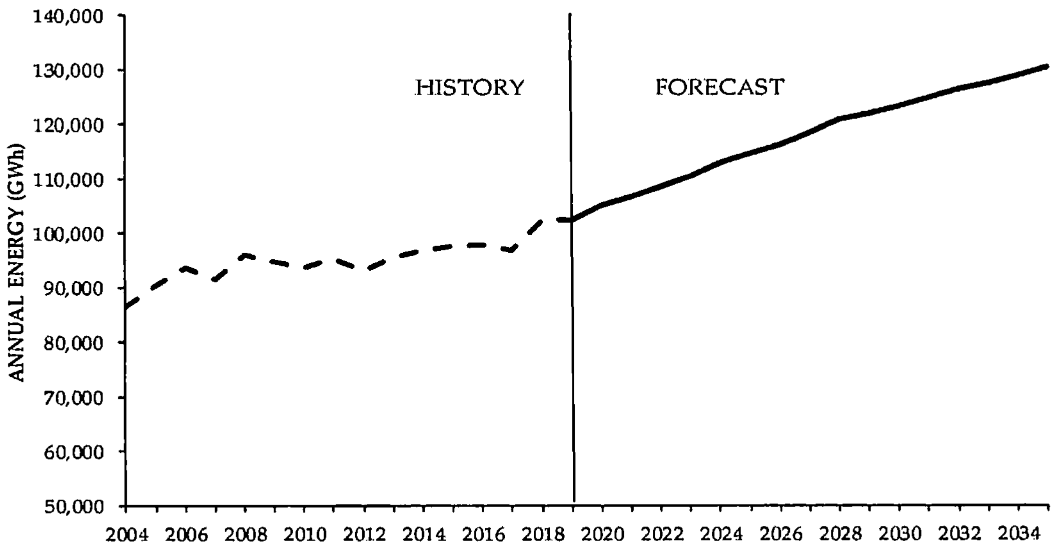


Figure 4.1.2.9 – DOM Zone Annual Energy Based on Company Load Forecast



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