Dominion Energy

Actions Speak Louder

Virginia Electric and Power Company

2022 Update to the 2020 Integrated Resource Plan

Case No. PUR-2022-00147 and Docket No. E-100, Sub 182

Filed September 1, 2022

Dogwood branch in bloom, state flower of Virginia and North Carolina

Executive Summary

Dominion Energy Corporate Office; Thomas F. Farrell building; Richmond, VA

Headquartered in Richmond, Virginia, Virginia Electric and Power Company (the "Company") currently serves approximately 2.7 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company is a subsidiary of Dominion Energy, Inc. ("Dominion Energy")—one of the nation's largest producers and transporters of energy, energizing the homes and businesses of more than seven million customers in 13 states with electricity or natural gas.

In May 2020, the Company filed a full integrated resource plan (the "2020 Plan") with the Virginia State Corporation Commission ("SCC") (Case No. PUR-2020-00035) and with the North Carolina Utilities Commission ("NCUC") (Docket No. E-100, Sub 165). On February 1, 2021, the SCC issued its Final Order on the 2020 Plan, setting forth information for the Company to include in future integrated resource plans and update filings. On November 19, 2021, the NCUC issued its Order accepting the 2020 Plan and finding it reasonable for planning purposes. The Company filed an update to the 2020 Plan with the SCC (Case No. PUR-2021-00201) and the NCUC (Docket No. E-100, Sub 165) ("2021 Update") in September 2021. The SCC and NCUC accepted the 2021 Update on October 28, 2021, and February 23, 2022, respectively. The Company now files this 2022 update ("2022 Update") to the 2020 Plan and the 2021 Update with the SCC and the NCUC consistent with all relevant Virginia and North Carolina laws, regulations, and commission orders, including where applicable the SCC's Final Order dated March 15, 2022, in Case No. PUR-2021-00146 that added additional requirements related to the Company's long-term system planning.

The 2020 Plan explained the Company's commitment to a clean energy future consistent with Dominion Energy's company-wide commitment to achieve net zero carbon dioxide ("CO_2") and methane emissions by 2050; the requirements established in Virginia aimed at a clean energy future through the Virginia Clean Economy Act of 2020 ("VCEA") and other legislation; and the goal of North Carolina to achieve statewide carbon neutrality by 2050. That commitment has not changed. Over the past year, the Company has received approvals related to nearly 2,600 megawatts ("MW") of offshore wind, over 850 MW of solar, and over 100 MW of energy storage. The Company also received approval from the SCC for the first phase of cost recovery related to the extension of the operating licenses of four nuclear units at North Anna and Surry, which will continue to provide over 30% of customers' energy needs for an additional 20 years. Through this energy transition, the Company is transforming its distribution grid to provide an enhanced platform for distributed energy resources ("DERs") and targeted demand-side management ("DSM") programs; more secure and reliable service, leading to the increased availability of DERs; and more ways for customers to save energy and money through DSM programs and other rate offerings. The Company has also received approval of new customer offerings in Virginia to support and incentivize the installation of charging infrastructure for electric vehicles ("EVs"), including an offering to support fleet electrification.

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

The 2022 Update was prepared for the Dominion Energy Load Serving Entity ("DOM LSE") within PJM Interconnection, LLC ("PJM"). It covers the 15-year period beginning in 2023 and continuing through 2037 (the "Planning Period"), using 2022 as the base year. In certain instances, the Company evaluates the longer 25-year period of 2023 to 2047 (the "Study Period"). Overall, the 2022 Update is an interim update meant for use as a long-term planning document based on a "snapshot in time" of current technologies, market information, and projections, and should be viewed in that context, not as a decision to pursue any specific project or action. Additionally, this 2022 Update is being filed amidst significant disruptions in global commodity markets and supply chains across the economy, as well as significant federal tax policy changes.

Drone inspecting transmission lines

In the 2020 Plan and the 2021 Update, the Company presented three alternative plans. In this 2022 Update, the Company has added two additional alternative plans for a total of five alternative plans (the "Alternative Plans"). The Company has also updated its long-term planning assumptions, including load forecasts, commodity prices, and projected costs of future resources. The Company updated its list of potential supply-side generation resources based on the state of current technology. For the first time the Company is adding small modular reactors ("SMRs"), an advanced nuclear technology, as an available resource beginning in 2032; the Company incorporated initial assumptions for this 2022 Update, and will continue to refine the way in which this carbon-free, dispatchable resource fits into the Company's commitment to reliability, affordability, and carbon reduction. The Company presents the following five 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 meets only applicable carbon regulations and the mandatory renewable energy portfolio standard program ("RPS Program") requirements of the VCEA. The Company presents this Alternative Plan in compliance with prior SCC and NCUC orders and for cost comparison purposes only. It is important to emphasize that Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.

- **Plan B**: This Alternative Plan 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 also preserves natural gas generation to address future system reliability, stability, and energy independence issues.

- **Plan C:** This Alternative Plan is like Plan B in preserving natural gas generation to address future system reliability, stability, and energy independence issues, with identical assumptions regarding the retirement of existing Company-owned carbon-emitting generation. Plan C differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Plan C conforms to the terms of the partial stipulation in Case No. PUR-2021-00146.

- **Plan D:** This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045, resulting in zero CO_2 emissions from the Company's fleet in 2046. If the Company retires all carbon-emitting units by the end of 2045, the Company will need to build and buy significant incremental capacity to reliably meet customer load. Plan D shows the Company building over 6,000 MW of incremental energy storage and more than 1,000 MW of incremental SMRs to meet this need when compared to Plan B. Even with these additional resources, Plan D results in the Company purchasing 5,000 MW of capacity in 2045 and beyond, raising concerns about system reliability and energy independence, including over-reliance on out-of-state capacity to meet customer needs. Over time as more renewable energy and energy storage resources are added to the system, the Company will learn if Plan D can maintain a reliable system.

- **Plan E:** This Alternative Plan is like Plan D in retiring all Company-owned carbon-emitting generation by the end of 2045. Plan E differs from Plan D in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Plan E conforms to the terms of the partial stipulation in Case No. PUR-2021-00146. Like Plan D, Plan E would require the Company to build and buy significant incremental capacity to reliably meet customer load. Over time as more renewable energy and energy storage resources are added to the system, the Company will learn if Plan E can maintain a reliable system.

All Alternative Plans utilize the load forecast prepared by PJM; assume a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia; and assume that Virginia exits the Regional Greenhouse Gas Initiative ("RGGI") before January 1, 2023. The 2022 Update also presents multiple sensitivities on various assumptions. Notably, the Company presents a sensitivity on Alternative Plan B that considers the effect of continued high fuel prices. The Company also presents sensitivities on all Alternative Plans that show the higher cost to customers if Virginia remains in RGGI.

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

Summary Table: 2022 Update Results

	Plan A	Plan B	Plan C	Plan D	Plan E
NPV Total ($B)	$68.1	$83.7	$77.2	$88.9	$88.1
Approximate CO_2 Emissions from Company in 2047 (Metric Tons)	18.9 M	5.1 M	4.9 M	0 M	0 M
Solar (MW)	14,829 15 yr. 26,829 25 yr.	13,692 15 yr. 25,692 25 yr.	13,329 15 yr. 25,329 25 yr.	13,812 15 yr. 27,012 25 yr.	16,586 15 yr. 29,786 25 yr.
Wind (MW)	— 15 yr. — 25 yr.	2,600 15 yr. 2,600 25 yr.	— 15 yr. 160 25 yr.	3,400 15 yr. 4,400 25 yr.	800 15 yr. 4,400 25 yr.
Storage (MW)	— 15 yr. — 25 yr.	2,620 15 yr. 3,070 25 yr.	30 15 yr. 2,400 25 yr.	3,220 15 yr. 9,220 25 yr.	4,030 15 yr. 10,030 25 yr.
Nuclear (MW)	— 15 yr. — 25 yr.	— 15 yr. 1,140 25 yr.	— 15 yr. 2,280 25 yr.	— 15 yr. 2,280 25 yr.	— 15 yr. 2,280 25 yr.
Natural Gas-Fired (MW)	1,940 15 yr. 2,425 25 yr.	— 15 yr. — 25 yr.	— 15 yr. — 25 yr.	— 15 yr. — 25 yr.	— 15 yr. — 25 yr.
Retirements (MW)	2,567 15 yr. 2,567 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 13,356 25 yr.	2,561 15 yr. 13,356 25 yr.

As can be seen in the Summary Table, all Alternative Plans show significant solar and energy storage development over the 25-year Study Period. Additionally, Plans B through E include development of SMRs. Incremental wind, solar, and energy storage resources are needed if the Company retires all carbon-emitting generation by the end of 2045, as shown in Plans D and E. While all Alternative Plans in this 2022 Update incorporate only known technologies, the Company fully expects that new technologies could take the place of today's technologies over the 15-year Planning Period and the 25-year Study Period. The Company intends to explore new and promising technologies that support a cleaner energy 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 filings.

The Company serves approximately 2.7 million electric customers in Virginia and North Carolina

The Company's comprehensive planning process considers emerging policy, market, regulatory, and technical developments that could affect its operations and, in turn, its customers. The Company provides the following discussion of significant developments requiring a major revision to the 2020 Plan and the 2021 Update, consistent with the requirements of the SCC and the NCUC. The Company must exercise some judgment when interpreting the terms "significant" and "major." This 2022 Update, therefore, includes a discussion of only those external events which, in the Company's judgment, require revision to the 2020 Plan and the 2021 Update.

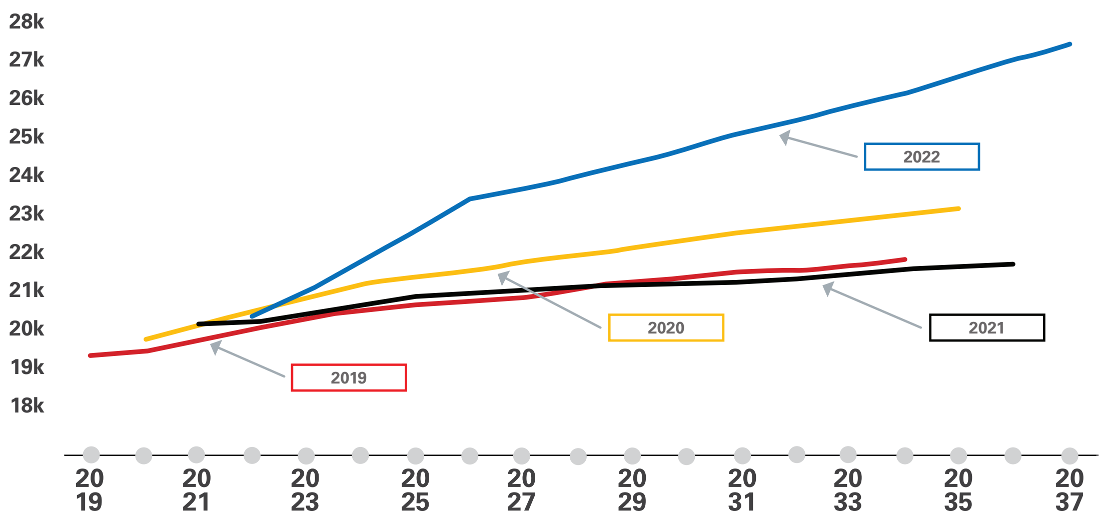
PJM Load Forecast

In the 2021 Update, the Company highlighted challenges with the 2021 PJM Load Forecast and expressed concerns with the use of PJM's load forecast in a long-term planning model. Unlike the last few years, the results of the 2022 PJM Load Forecast are similar to the 2022 Company Load Forecast. Figure 1.1.1 compares the PJM DOM Zone Forecast for the years 2019 through 2022.

In its 2022 PJM Load Forecast, PJM incorporated changes to its load forecasting methodology and utilized the latest data center forecast provided by the Company and Northern Virginia Electric Cooperative, which resulted in a significant increase in the load forecast compared to 2021. PJM's forecasting adjustments addressed the Company's concerns with PJM's utilization of a long-term trend variable as discussed in the 2021 Update. PJM also adjusted its method of incorporating data center forecasts into the overall forecast. Previously, the data center forecast was "implicitly" incorporated into the DOM Zone forecast by way of adjusting an input variable; by contrast, the 2022 PJM Load Forecast isolated the non-data center forecast from the data center forecast, thereby incorporating the data center forecast explicitly. These changes provide more forecast transparency.

Even with these revisions, a few challenges remain with utilization of PJM's load forecast for the Company's long-term resource planning process related to region-specific nuances, forecast timing, and forecast translation from the DOM Zone to the DOM LSE. These challenges are not a criticism of the PJM forecast itself but are associated with its use of that forecast for the Company's long-term planning. Accordingly, while the Company has utilized the 2022 PJM Load Forecast in the development of all Alternative Plans, as required, the Company also shows a sensitivity of Alternative Plan B using the 2021 Company Load Forecast.

Figure 1.1.1: PJM DOM Zone Forecast, 2019 through 2022



Nuclear

As a carbon-free complement to renewable energy generation, nuclear generation provides a reliable and clean source of energy. Nuclear power thus remains a fundamental component of the clean energy transition to net zero emissions and a necessary resource to maintain reliability and affordability. This 2022 Update includes both 20-year nuclear license extensions at North Anna and Surry Power Stations, as well as SMRs as a future supply-side resource option.

Nuclear Relicensing

The licenses to operate the two nuclear units at the Company's Surry Power Station were renewed by the Nuclear Regulatory Commission ("NRC") on May 4, 2021, permitting continued operation through 2052 for Unit 1 and through 2053 for Unit 2.

The Company submitted its application to the NRC to renew the licenses for its two units at the North Anna Power Station in August 2020. The Company continues to engage with the NRC, consultants, and industry partners regarding additional information requested for the application related to certain potential environmental impacts of operating North Anna Units 1 and 2 from 60 to 80 years. The Company expects to submit supplemental environmental information to the NRC in 2022. While the Company does not have an expected time frame for final approval and issuance of the renewed licenses at this time, the Company remains confident that it will receive the renewed licenses for these units, which would permit North Anna Units 1 and 2 to continue operating until 2058 and 2060, respectively.

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

Small Modular Reactors

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

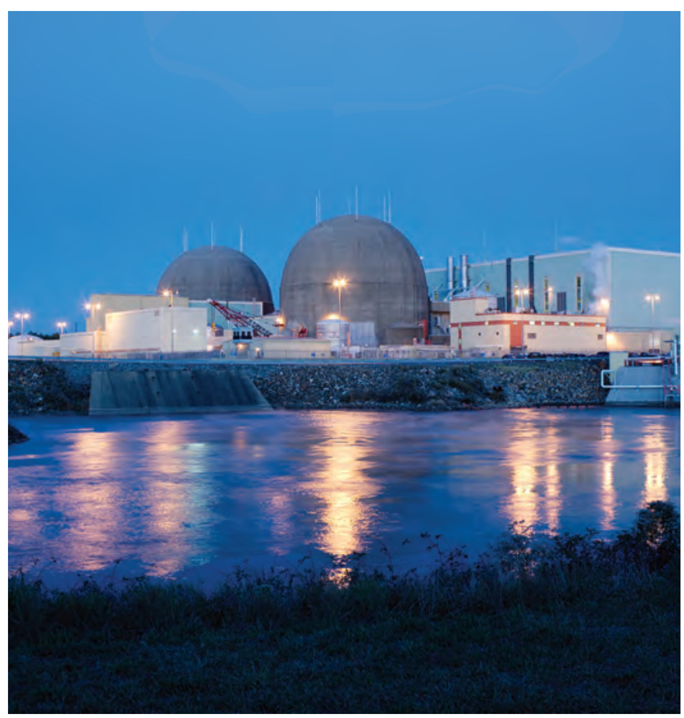
Among the key benefits and improvements of SMRs over traditional nuclear technology is the increased use of passive safety systems. Passive safety systems rely on natural forces such as gravity, pressure differences, or natural heat convection to accomplish safety functions without the need for operator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

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

Although this technology has not yet been deployed at scale, SMR design activities and regulatory licensing are accelerating both domestically and abroad. The NRC has engaged in varying degrees of pre-application activities with several SMR reactor designers and license applicants. Earlier this year, the NRC issued a final rule certifying the first SMR design in the United States, with others expected to be approved over the next several years.

Based on the status of SMR development, the Company anticipates SMRs could be a feasible supply-side resource as soon as the early 2030s. The Company has thus included SMRs as a supply-side option starting in December 2032 in all Alternative Plans. Starting in 2034, the Company assumed that one 285 MW SMR could be built per year. For some light-water SMR designs that utilize current nuclear fuel technologies with an available supply chain, the commercial availability may be even sooner.

The Company plans to continue evaluating the feasibility, operating parameters, and costs of SMRs and will update modeling assumptions related to SMRs in future filings. Potential cost reductions relative to the assumptions reflected in the 2022 Update may be realized as the design of SMRs matures and as anticipated construction schedules are established. Based on updated capital, operating and maintenance costs, continued progress of licensing timelines, and new policy initiatives or legislative changes, it is conceivable that the deployment of SMRs could be further accelerated by the Company with the first SMR being placed in service within a decade.



Surry Power Station; Surry County, VA

Virginia REC Market

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

REC prices within existing PJM REC markets have risen since the enactment of the VCEA in part because of the increased demand for RECs to comply with the mandatory RPS Program. The mandatory RPS Program will also result in the establishment of a new Virginia REC market because of the requirement for the Company to retire a significant number of RECs from Virginia-sited renewable energy facilities beginning in 2025. Although a market for Virginia in-state RECs has not fully developed, the 2022 Update includes an initial Virginia REC price forecast. Based on current market dynamics, the price for RECs in the Virginia REC market will likely be equal to or higher than the PJM REC market price.

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

Scott Solar Facility; Powhatan County, VA

According to the Company's current estimates, the Company's need for RECs from eligible resources will grow from approximately 15 million in 2025 to approximately 46 million in 2035. The development targets set forth in the VCEA seem to recognize as much by requiring the Company and Appalachian Power Company to petition the SCC for the necessary approvals to construct, purchase, or acquire a significant amount of solar and wind resources. In the absence of the two incumbent electric utilities in Virginia developing these resources—either through construction or acquisition by the utility or through incentivizing the construction by third-party developers through power purchase agreements ("PPAs")—it is unlikely that the necessary renewable energy development in Virginia would materialize to meet the RPS Program requirements. Because the Virginia REC market is in its infancy, it is difficult to predict what the future REC supply will be. However, if the market does not develop and the REC market is undersupplied, the market clearing price of RECs is likely to become the equivalent of the VCEA-imposed deficiency payment for supply and demand to be in equilibrium. In this 2022 Update, the Company allowed the model to select 100% of RECs for RPS Program compliance as purchases from a PJM REC market through 2024, and then allowed the model to select 25% of RECs from a PJM REC market for the remainder of the Study Period. Based on the concerns noted above, the Company allowed the model to select 1% of RECs for RPS Program compliance as purchases from a Virginia REC market.

Considering the 2022 PJM Load Forecast, growing RPS Program requirements in Virginia and throughout PJM, and a constrained development environment, the Company does not believe the REC markets will support more than 26% of its RPS Program requirements after 2025. The Company took a conservative approach for modeling purposes, assuming that the majority of these REC purchases would take place in a lower-priced PJM REC market.

Carbon Regulations

Significant developments have occurred related to carbon regulations at both the federal and state level since the 2021 Update.

Federal Carbon Regulation

On January 19, 2021, the D.C. Circuit Court vacated the Affordable Clean Energy ("ACE") Rule—the less stringent replacement of the Clean Power Plan. The Environmental Protection Agency (the "EPA") is currently working on a new set of guidelines to direct states in regulating greenhouse gases from existing fossil-fuel fired generating units within their borders. According to current EPA guidance, the EPA intends to issue a proposed rule in March 2023, with no timetable for a final rule at this time.

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

RGGI

As explained in the 2020 Plan, efforts were made in 2020 for Virginia to become a full participant in RGGI, which resulted in Virginia joining RGGI as of January 1, 2021. On January 15, 2022, Virginia Governor Youngkin issued Executive Order Number Nine ("EO9") directing state agencies to take certain actions to "re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it." On March 11, 2022, as directed by EO9, the Virginia Department of Environmental Quality issued a report that presented a path for Virginia to end its participation in RGGI. Specifically, the report included a draft emergency regulation to repeal the entire existing carbon trading regulation, along with a brief description of the process for promulgating an emergency regulation under Virginia law.

For this 2022 Update, the Company had commodity price forecasts prepared to reflect both Virginia remaining in RGGI and Virginia exiting RGGI before January 1, 2023. Based on currently available information and assumptions, an emergency regulation withdrawing Virginia from RGGI could become effective by the end of 2022, which would eliminate the Company's RGGI compliance obligations. Considering the planned actions by the current administration to withdraw Virginia from RGGI, the Company modeled all Alternative Plans assuming Virginia exiting RGGI before January 1, 2023. The Company then performed sensitivities on all Alternative Plans to show the impact of Virginia remaining in RGGI. As can be seen in the results of the sensitivities presented in ***Sensitivity Analysis***, remaining in RGGI would result in higher energy costs for customers in all scenarios.

Federal Interconnection Queue Reform

In early 2021, PJM announced a pause in its generation queue study process due to the backlog of queue projects waiting on final interconnection service agreements ("ISA"). In conjunction with this queue pause, PJM started a stakeholder process—the Interconnection Process Reform

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

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

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

Infrastructure Investment and Jobs Act

The Infrastructure Investment and Jobs Act ("IIJA") was enacted on November 15, 2021, to comprehensively invest in the nation's infrastructure. Relevant to utilities, the IIJA aims to build a national network of EV chargers; upgrade power infrastructure to deliver clean, reliable energy across the country and deploy cutting-edge energy technology to achieve a zero-emissions future; and make infrastructure resilient against the impacts of climate change, cyber-attacks, and extreme weather events. The IIJA provides several funding opportunities, some of which will be directly available to utilities and some of which will be partnership-based, meaning, for example, partnerships between the Company and school districts in its territory for electrification of school buses.

While the Company is developing its strategies to potentially apply for IIJA's competitive funding, planning is at a preliminary stage. The Company does not intend to limit its evaluation of IIJA funding opportunities to a one-time review of potential programs. Instead, the Company intends to continually review available IIJA funding opportunities over the programs' five-year time horizon. Furthermore, the Company intends to actively participate in as many opportunities as align with its operations in Virginia and North Carolina and as provide overall net benefits to its customers.

Electric Vehicle (EV) charging station

Commodity Price and Cost Assumptions

This 2022 Update incorporates updated commodity price forecasts and cost assumptions. As with the 2021 Update, the updated commodity price forecasts include the regional impacts of the VCEA along with other market developments identified by ICF Resources, LLC ("ICF"), including recent commodity price volatility and the 2022 PJM Load Forecast update, as well as the effect of these developments on markets for power, capacity, and environmental attributes.

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

Buckingham Solar Farm; Buckingham, VA

This 2022 Update also incorporates updated construction costs for new resources. These projected costs incorporate market changes over the past year affected by record levels of inflation and global supply chain disruptions that are placing upward pressure on material and commodity costs. The result is a material increase in overall build costs, particularly for solar and storage resources as compared to the 2021 Update.

For this 2022 Update, the projected solar and energy storage capital costs are based on the market in Virginia using cost data from Company-developed projects through 2021. Given the currently volatile supply chain environment and to account for continued market demand challenges, 2023 costs were then held constant through 2026. Beyond 2026, the capital cost increases or decreases for resources were based on the 2021 National Renewable Energy Laboratory ("NREL") annual technology baseline assumptions for the moderate scenario. For PPA cost assumptions, a market index price was created using the weighted average first year price from conforming PPA bids in the Company's request for proposals ("RFP") for utility-scale solar, onshore wind, and energy storage resources. The market index price was held constant through 2026 and then adjusted based on the NREL moderate scenario. Notably, since finalizing modeling for this 2022 Update, several of the PPAs included in the market index price withdrew from consideration due to cost concerns.

Inflation Reduction Act

In August 2022, Congress passed the Inflation Reduction Act, which includes various climate and energy provisions expected to have a positive impact on current and future Company green energy investments. President Biden signed this measure into law on August 16, 2022. The Inflation Reduction Act includes $369 billion for climate and clean energy provisions including increased tax credits for solar, storage, nuclear, and wind. The Company is actively reviewing the provisions of the Inflation Reduction Act and will incorporate its provisions into future filings where appropriate.

Results of 2022 Update

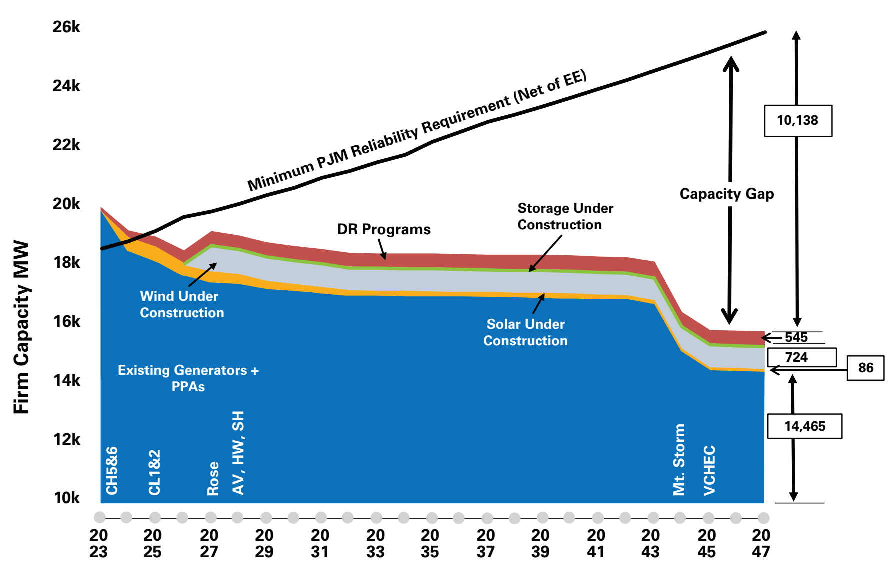
Dominion Energy's Coastal Virginia Offshore Wind Turbine

Based on the developments discussed above, and consistent with the requirements of the SCC and the NCUC, the Company has made adjustments to the type and size of resources identified in the 2020 Plan and the 2021 Update. As always, the Company's options for meeting its customers' future 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 electric rate stability, increasing energy independence, promoting economic development, 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.

Capacity, Energy, and REC Positions

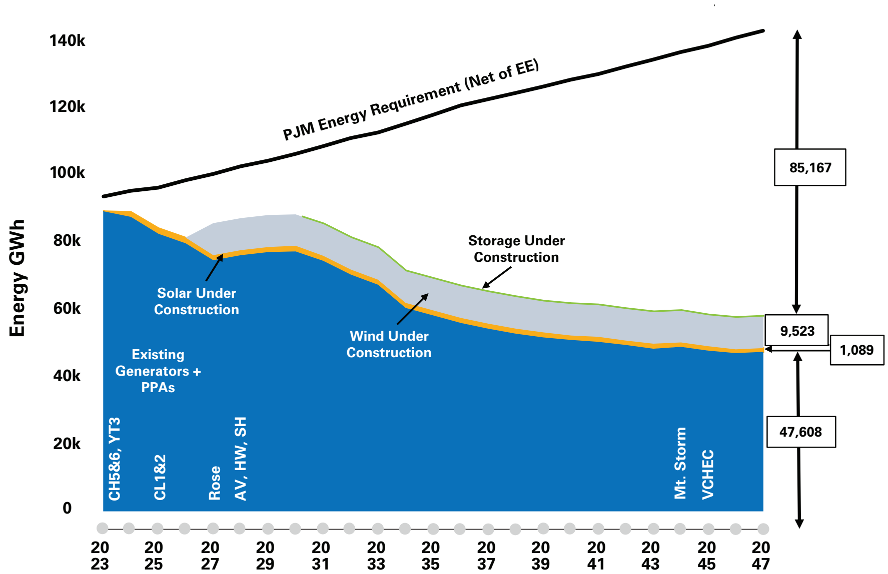
Figures 2.1.1, 2.1.2, and 2.1.3 represent the Company's current capacity, energy, and REC positions under the Virginia RPS Program using unit retirement assumptions in Alternative Plan B.

Figure 2.1.1: Current Company Capacity Position (2023 to 2047)



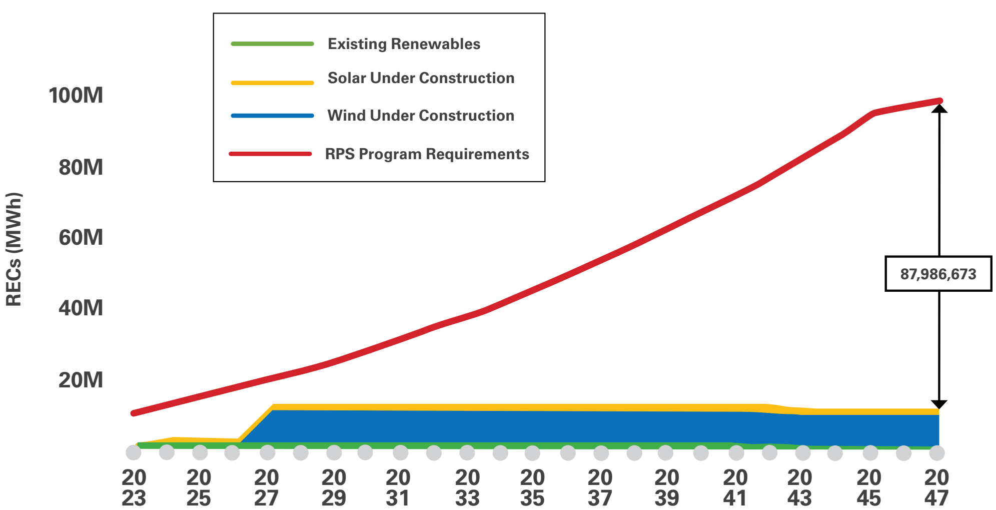
Notes: "PPAs" = power purchase agreements; "DR" = demand response; "EE" = energy efficiency; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass).

Figure 2.1.2: Current Company Energy Position (2023 to 2047)



Notes: "PPAs" = power purchase agreements; "DR" = demand response; "EE" = energy efficiency; "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); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass).

Figure 2.1.3: Current Company REC Position under Virginia RPS Program (2023 to 2047)



Alternative Plans

The 2022 Update presents alternative paths forward for the Company to meet the future capacity and energy needs of its customers, as well as customers' REC needs under the Virginia RPS Program. Notably, planning work remains ongoing and necessary to test the grid under different conditions to ensure system reliability and security in the long term.

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

Plan A: This Alternative Plan presents a least-cost plan that meets only applicable carbon regulations and the mandatory Virginia RPS Program. The Company presents this Alternative Plan in compliance with prior SCC and NCUC orders and for cost comparison purposes only. For Plan A, the Company did not force the model to select any specific resource and did not exclude any reasonable resource. Consistent with this directive from prior orders, the Company did not exclude carbon-emitting resources as an option to reliably meet customers' energy and capacity needs and allowed the model to select the retirement dates for existing units on a least-cost optimization basis without regard for other factors that the Company considers when evaluating unit retirements. It is important to emphasize that Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA, including the statutory split of 65% Company-owned resource to 35% PPAs through 2035. The Company does not consider Plan A as a true alternative path forward based on these concerns, as well as the over-reliance on third-party solar PPAs to meet customer needs, which comes with risks related to accountability and project execution. It is worth noting that even in Plan A where most of the Company's existing resources stay online, a significant amount of new development is required to meet growing customer capacity and energy needs.

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 also preserves natural gas-fired generation to address future system reliability, stability, and energy independence issues.[1] This allows the Company to maintain gas generation for reliability while having the flexibility to run these units less as renewable generation increases. Over the Study Period, this Alternative Plan includes the development of nearly 25.7 gigawatts ("GW") of additional solar capacity, approximately 2.6 GW of additional offshore wind capacity, approximately 3.1 GW of additional energy storage capacity, and approximately 1.1 GW of SMRs.

Plan C: This Alternative Plan is like Plan B in preserving natural gas-fired generation to address future system reliability, stability, and energy independence issues, with identical assumptions regarding the retirement of existing Company-owned carbon-emitting generation. Plan C differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Plan C conforms to the terms of the partial stipulation in Case No. PUR-2021-00146.

Plan D: This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045 resulting in zero CO_2 emissions from the Company's fleet in 2046. If the Company retires all carbon-emitting units by the end of 2045, the Company will need to build and buy significant incremental capacity to reliably meet customer load. Plan D shows the Company building approximately 6.2 GW of incremental energy storage, 1.8 GW of onshore wind, and 1.1 GW of incremental SMRs to meet this need when compared to Plan B. Even with the addition of SMRs and onshore wind, along with a significant

[1] The natural gas resources preserved in Alternative Plan B are consistent with the 2021 Update.

incremental increase in energy storage, Plan D results in the Company purchasing over 5 GW of capacity in 2045 and beyond, raising concerns about system reliability and energy independence, including reliance on out-of-state capacity to meet customer needs. In addition, the significant onshore wind additions are a concern due to the amount of land that would be required to meet this need. Over time as more renewable energy and energy storage resources are added to the system, the Company will learn if Plan D is capable of maintaining a reliable system.

Plan E: This Alternative Plan is like Plan D in retiring all Company-owned carbon-emitting generation by the end of 2045. Plan E differs from Plan D in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Like Plan D, under Plan E the Company would need to build and buy significant incremental capacity to reliably meet customer load. Plan E conforms to the terms of the partial stipulation in Case No. PUR-2021-00146. Over time as more renewable energy and energy storage resources are added to the system, the Company will learn if Plan E is capable of maintaining a reliable system.

All Alternative Plans utilize the load forecast prepared by PJM; assume a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia; and assume Virginia exits RGGI before January 1, 2023. In addition, Alternative Plans B, C, D, and E incorporate the social cost of carbon into their dispatch modeling, as discussed in ***Social Cost of Carbon***.

Figures 2.2.1 through 2.2.5 show the build plans for each Alternative Plan. The resource additions shown in these figures are incremental to existing generation and approved generation under construction, including nearly 2,600 MW of offshore wind. See Appendix 2A for the capacity, energy, and RECs associated with all Alternative Plans. See Appendix 2B for the capacity-related information directed by the SCC.

Dominion Energy's Coastal Virginia Offshore Wind Project

Figure 2.2.1: Alternative Plan A (Nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2023	-	-	-	-	-	-	-	200	YT3, CH5-6
2024	-	-	-	-	-	-	-	-	VCHEC, BIO
2025	-	428	1	-	-	-	-	1,100	-
2026	-	1,200	-	-	-	-	-	1,000	-
2027	-	1,200	-	-	-	-	-	-	-
2028	-	1,200	-	-	-	-	-	-	-
2029	-	1,200	-	-	-	-	-	-	-
2030	-	1,200	-	-	-	-	-	200	-
2031	-	1,200	-	-	-	-	-	600	-
2032	-	1,200	-	-	-	-	-	1,000	-
2033	-	1,200	-	-	-	-	-	1,100	-
2034	-	1,200	-	-	-	485	-	700	-
2035	-	1,200	-	-	-	485	-	500	-
2036	-	1,200	-	-	-	485	-	200	-
2037	-	1,200	-	-	-	485	-	300	-
15-Year Subtotal	-	14,828	1	-	-	1,940	-	6,900	-
2038	-	1,200	-	-	-	485	-	-	-
2039	-	1,200	-	-	-	-	-	100	-
2040	-	1,200	-	-	-	-	-	200	-
2041	-	1,200	-	-	-	-	-	400	-
2042	-	1,200	-	-	-	-	-	700	-
2043	-	1,200	-	-	-	-	-	1,100	-
2044	-	1,200	-	-	-	-	-	1,400	-
2045	-	1,200	-	-	-	-	-	1,800	-
2046	-	1,200	-	-	-	-	-	2,300	-
2047	-	1,200	-	-	-	-	-	2,700	-
25-Year Total	-	26,828	1	-	-	2,425	-	17,600	-

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "YT3" = Yorktown Unit 3 (oil); "CH5-6" = Chesterfield Units 5 & 6 (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "BIO" = Altavista, Hopewell, and Southampton (biomass).

Figure 2.2.2: Alternative Plan B (Nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2023	-	-	-	-	-	-	-	-	YT3, CH5&6
2024	-	-	23	-	-	-	-	-	-
2025	397	428	65	-	130	-	-	-	CL1&2
2026	812	315	110	-	120	-	-	-	-
2027	585	315	120	-	120	-	-	-	Rosemary
2028	585	315	120	-	150	-	-	-	Biomass
2029	624	336	100	-	210	-	-	-	-
2030	624	336	98	-	210	-	-	-	-
2031	624	336	90	-	240	-	-	-	-
2032	624	336	70	-	270	-	-	-	-
2033	624	336	66	-	270	-	-	-	-
2034	624	336	66	2,600	300	-	-	-	-
2035	624	336	66	-	300	-	-	-	-
2036	624	336	66	-	300	-	-	-	-
2037	780	420	-	-	-	-	-	-	-
15-Year Subtotal	**8,151**	**4,481**	**1,060**	**2,600**	**2,620**	**-**	**-**	**-**	**-**
2038	780	420	-	-	-	-	-	-	-
2039	780	420	-	-	-	-	-	-	-
2040	780	420	-	-	-	-	-	-	-
2041	780	420	-	-	-	-	-	-	-
2042	780	420	-	-	-	-	285	-	-
2043	780	420	-	-	-	-	285	-	-
2044	780	420	-	-	-	-	-	1,700	Mt Storm
2045	780	420	-	-	-	-	285	2,400	VCHEC
2046	780	420	-	-	150	-	285	2,500	-
2047	780	420	-	-	300	-	-	2,700	-
25-Year Total	**15,951**	**8,681**	**1,060**	**2,600**	**3,070**	**-**	**1,140**	**9,300**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "YT3" = Yorktown Unit 3 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "CL1&2" = Clover Units 1 & 2 (coal); Rosemary (oil); "Biomass" = Altavista, Hopewell, and Southampton (biomass); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass).

Figure 2.2.3: Alternative Plan C (Nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2023	-	-	-	-	-	-	-	-	YT3, CH5&6
2024	-	-	-	-	-	-	-	-	-
2025	-	428	1	-	-	-	-	-	CL1&2
2026	78	42	-	-	-	-	-	900	-
2027	507	273	-	-	-	-	-	200	Rosemary
2028	780	420	-	-	-	-	-	100	Biomass
2029	780	420	-	-	-	-	-	300	-
2030	780	420	-	-	-	-	-	500	-
2031	780	420	-	-	-	-	-	800	-
2032	780	420	-	-	-	-	-	1,200	-
2033	780	420	-	-	-	-	-	1,300	-
2034	780	420	-	-	30	-	-	1,300	-
2035	780	420	-	-	-	-	-	1,600	-
2036	780	420	-	-	-	-	-	1,700	-
2037	780	420	-	-	-	-	-	1,900	-
15-Year Subtotal	**8,385**	**4,943**	**1**	**-**	**30**	**-**	**-**	**11,800**	**-**
2038	780	420	-	-	240	-	-	1,800	-
2039	780	420	-	80	180	-	-	1,800	-
2040	780	420	-	80	300	-	285	1,500	-
2041	780	420	-	-	300	-	285	1,100	-
2042	780	420	-	-	300	-	285	800	-
2043	780	420	-	-	300	-	285	700	-
2044	780	420	-	-	300	-	285	2,200	Mt Storm
2045	780	420	-	-	300	-	285	2,700	VCHEC
2046	780	420	-	-	30	-	285	2,700	-
2047	780	420	-	-	120	-	285	2,700	-
25-Year Total	**16,185**	**9,143**	**1**	**160**	**2,400**	**-**	**2,280**	**29,800**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "YT3" = Yorktown Unit 3 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "CL1&2" = Clover Units 1 & 2 (coal); Rosemary (oil); "Biomass" = Altavista, Hopewell, and Southampton (biomass); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass)..

Figure 2.2.4: Alternative Plan D (Nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2023	-	-	-	-	-	-	-	-	YT3, CH5&6
2024	-	-	23	-	-	-	-	-	-
2025	397	428	65	-	130	-	-	-	CL1&2
2026	812	315	110	-	120	-	-	100	-
2027	585	315	120	-	120	-	-	-	Rosemary
2028	585	315	120	80	150	-	-	-	Biomass
2029	624	336	100	80	210	-	-	-	-
2030	624	336	98	80	210	-	-	-	-
2031	624	336	90	80	240	-	-	-	-
2032	624	336	70	80	270	-	-	-	-
2033	624	336	66	80	270	-	-	-	-
2034	624	336	66	2,680	300	-	-	-	-
2035	624	336	66	80	300	-	-	-	-
2036	624	336	66	80	300	-	-	-	-
2037	780	420	120	80	600	-	-	-	SA
15-Year Subtotal	**8,151**	**4,481**	**1,180**	**3,400**	**3,220**	**-**	**-**	**100**	**-**
2038	780	420	120	80	600	-	-	-	CH7&8, ER, GN
2039	780	420	120	80	600	-	-	-	PP6, BG
2040	780	420	120	80	600	-	285	-	-
2041	780	420	120	80	600	-	285	-	DT
2042	780	420	120	80	600	-	285	-	-
2043	780	420	120	80	600	-	285	-	LS
2044	780	420	120	80	600	-	285	300	Mt Storm
2045	780	420	120	280	600	-	285	5,500	3x1, VCHEC, Rem
2046	780	420	120	80	600	-	285	5,200	-
2047	780	420	120	80	600	-	285	5,000	-
25-Year Total	**15,951**	**8,681**	**2,380**	**4,400**	**9,220**	**-**	**2,280**	**16,100**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "YT3" = Yorktown Unit 3 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "CL1&2" = Clover Units 1 & 2 (coal); Rosemary (oil); "Biomass" = Altavista, Hopewell, and Southampton (biomass); "SA" = South Anna (gas); "CH7&8" = Chesterfield 7 & 8 (gas); "ER" = Elizabeth River (gas/oil); "GN" = Gravel Neck (gas/oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "DT" = Darbytown (gas/oil); "LS" = Ladysmith (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "3x1" = Warren, Brunswick, and Greensville (gas); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas/oil).

Figure 2.2.5: Alternative Plan E (Nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2023	-	-	-	-	-	-	-	-	YT3, CH5&6
2024	-	-	8	-	-	-	-	-	-
2025	397	114	-	-	130	-	-	-	CL1&2
2026	1,007	420	120	-	300	-	-	-	-
2027	780	420	120	-	300	-	-	-	Rosemary
2028	780	420	120	80	300	-	-	-	Biomass
2029	780	420	120	80	300	-	-	-	-
2030	780	420	120	80	300	-	-	-	-
2031	780	420	120	80	300	-	-	-	-
2032	780	420	120	80	300	-	-	-	-
2033	780	420	120	80	300	-	-	-	-
2034	780	420	120	80	300	-	-	-	-
2035	780	420	120	80	300	-	-	-	-
2036	780	420	120	80	300	-	-	-	-
2037	780	420	120	80	600	-	-	-	SA
15-Year Subtotal	**9,984**	**5,154**	**1,448**	**800**	**4,030**	**-**	**-**	**-**	**-**
2038	780	420	120	80	600	-	-	-	CH7&8, ER, GN
2039	780	420	120	80	600	-	-	-	PP6, BG
2040	780	420	120	80	600	-	285	-	-
2041	780	420	120	80	600	-	285	-	DT
2042	780	420	120	80	600	-	285	-	-
2043	780	420	120	80	600	-	285	-	LS
2044	780	420	120	80	600	-	285	-	Mt Storm
2045	780	420	120	2,880	600	-	285	4,400	3x1, VCHEC, Rem
2046	780	420	120	80	600	-	285	4,300	-
2047	780	420	120	80	600	-	285	4,200	-
25-Year Total	**17,784**	**9,354**	**2,648**	**4,400**	**10,030**	**-**	**2,280**	**12,900**	**-**

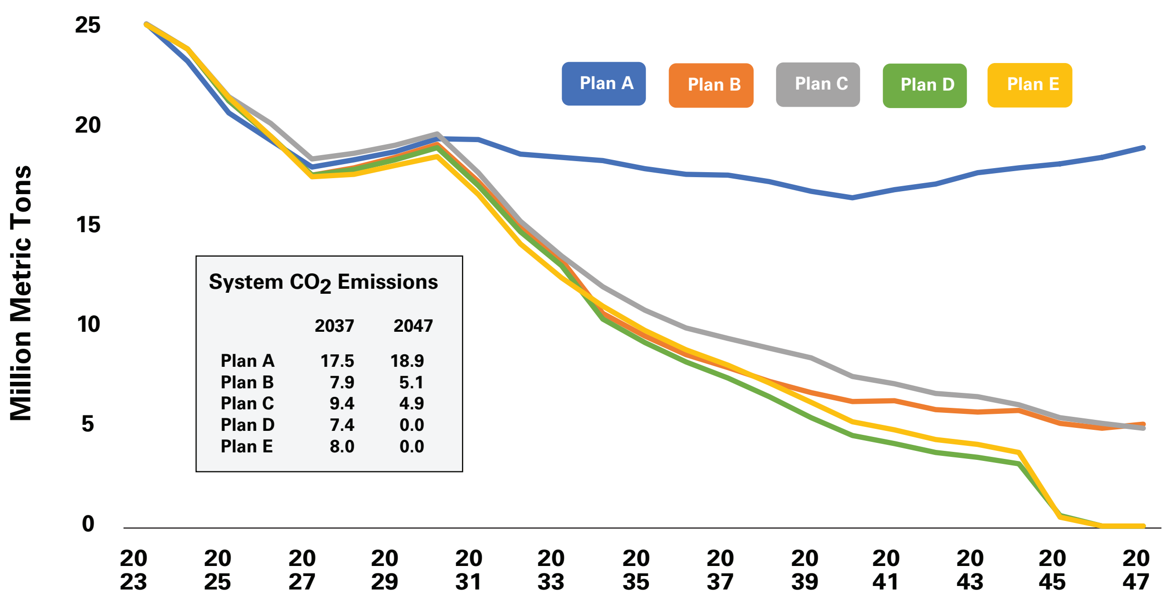
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "YT3" = Yorktown Unit 3 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "CL1&2" = Clover Units 1 & 2 (coal); Rosemary (oil); "Biomass" = Altavista, Hopewell, and Southampton (biomass); "SA" = South Anna (gas); "CH7&8" = Chesterfield 7 & 8 (gas); "ER" = Elizabeth River (gas/oil); "GN" = Gravel Neck (gas/oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "DT" = Darbytown (gas/oil); "LS" = Ladysmith (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "3x1" = Warren, Brunswick, and Greensville (gas); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas/oil).

Overall, the higher 2022 PJM Load Forecast caused a significant increase in capacity, energy, and REC needs for each Alternative Plan compared to the 2021 Update, highlighting the need for a substantial amount of new resource development to reliably serve customers. Accordingly, these results suggest that it remains prudent to proceed with the development of solar, wind, and energy storage resources envisioned by the VCEA, as shown in Plans B and D.

Like the 2021 Update and based on the current snapshot in time, Alternative Plans B through E do not include 970 MW of natural gas-fired combustion turbines as a placeholder to address system reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generator facilities. However, it is likely that additional quick start, dispatchable resources will be needed in the future. Associated reliability analyses are complex, under development, and still ongoing, as discussed in Chapter 7. Future filings will be updated based on the results and findings of these reliability analyses.

Figure 2.2.6 shows projected CO_2 emissions from the Company's fleet for the duration of the Study Period. Plans B and D lead to a faster decline in the system CO_2 than the corresponding economically selected plans.

Figure 2.2.6: System CO_2 Output from Company Fleet for Alternative Plans



System CO_2 Emissions

	2037	2047
Plan A	17.5	18.9
Plan B	7.9	5.1
Plan C	9.4	4.9
Plan D	7.4	0.0
Plan E	8.0	0.0

Reliability Analyses of Alternative Plans

The Company completed a high-level assessment of the potential reliability of the Company's transmission system under the build plans shown in Alternative Plans A through E, with the goal of identifying any potential reliability concerns. A significant factor in future transmission system reliability is the retirement of synchronous generation facilities. Based on the time it takes to complete this type of analysis, the Company used Alternative Plans A, B, and C from the 2021 as a proxy for Alternative Plans A, B/C, and D/E in this 2022 Update. This approach provides a reasonable approximation of potential reliability concerns because of the similarity of existing unit retirements within those groups. The Company performed this analysis by replicating the general synchronous generation retirement trend described in these Alternative Plans. The primary limitation of using Alternative Plans A, B, and C from the 2021 Update as a proxy is that the 2021 Update did not include SMRs, which are included as a resource for the first time in this 2022 Update. The Company will incorporate SMRs into its reliability analyses in future filings. The Company provides a summary of its assessment here, with additional details provided in Chapter 7 of this 2022 Update:

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

Plans B/C: While the Company has transmission system reliability concerns when compared to Plan A, concerns regarding Plans B/C are alleviated in part by the preservation of natural gas-fired generation beyond 2045 to address future system reliability, stability, and energy independence issues. Yet Plans B/C show deterioration of inertia response as a result of further retirement of rotating machines when compared to Plan A; in addition, average fault current over the Company system decreased when compared to Plan A.

Plans D/E: The Company has concerns regarding whether Plans D/E would be capable of maintaining a reliable system with the retirement of all carbon-emitting units—the traditional synchronous generators relied on for system reliability—by the end of 2045. The Company's analysis showed suboptimal primary frequency response following the loss of a large synchronous generation. The analyses completed for Plans D/E also showed deterioration of inertia response when compared to Plans A and B/C; in addition, average fault current over the Company system decreased when compared to Plans A and B/C.

Net Present Value Comparison

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

Figure 2.4.1: NPV Results ($B)

	Plan A	Plan B	Plan C	Plan D	Plan E
Total System Costs	$54.1	$69.8	$63.3	$75.0	$74.1
Grid Transformation Plan (Net of Benefits)	$1.3	$1.3	$1.3	$1.3	$1.3
Strategic Underground Program	$0.9	$0.9	$0.9	$0.9	$0.9
Transmission Underground Pilots	$0.1	$0.1	$0.1	$0.1	$0.1
Transmission	$9.7	$9.7	$9.7	$9.7	$9.7
Other Capital	$2.0	$2.0	$2.0	$2.0	$2.0
Total Plan NPV	**$68.1**	**$83.7**	**$77.2**	**$88.9**	**$88.1**
Plan Delta vs. Plan A	N/A	$15.6	$9.1	$20.8	$20.0

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

Virginia Consolidated Bill Analysis

The Company completed a consolidated bill analysis for each Alternative Plan presented in the 2022 Update. This analysis encompasses three different customer classes and spans 2022 through 2035.

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

Under the Directed Methodology, all Alternative Plans also assume a capacity factor for existing and future solar resources based on the lower of the design capacity factor or the three-year average of the Company's solar facilities in Virginia. As discussed in prior proceedings, the Company believes that a projected design capacity factor for future solar facilities better reflects their long-term output and has therefore incorporated such capacity factors into one of the sensitivities presented in ***Sensitivity Analyses***.

Given these concerns with the Directed Methodology, the Company has also calculated projected bills under each Alternative Plan using (i) forecasted system and class sales growth and the associated class allocation factors and (ii) a design capacity factor for future solar resources ("Company Methodology").

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

Figure 2.5.1 shows that, when using the Company Methodology and a baseline of May 1, 2020, the typical residential customer's bill is expected to increase at a compound annual growth rate ("CAGR") of 2.7% through 2035. When using the Company Methodology and December 31, 2019, as the baseline, the projected increase in the typical residential customer's bill is approximately 2.3% on a compound annual basis.

As an additional point of comparison, in July 2008—the year following passage of the Virginia Electric Utility Regulation Act—the electric bill of the Company's typical residential customer in Virginia was $107.20. Using 2008 as the baseline, the projected CAGR for the typical residential customer bill through 2035 is approximately 1.9% using the Company Methodology.

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

	Plan B – Company Methodology[1]			Plan B – Directed Methodology		
	Projected Bill	CAGR Dec 2019	CAGR May 2020	Projected Bill	CAGR Dec 2019	CAGR May 2020
Dec. 31, 2019	$122.66			$122.66		
May 1, 2020	$116.18			$116.18		
Year End 2030	$165.64	2.8%	3.4%	$185.81	3.8%	4.5%
Year End 2035	$177.48	2.3%	2.7%	$213.36	3.5%	4.0%
Total Bill Increase *(May 2020-2035)*	$61.30			$97.18		

Note: (1) Derived using the system resources selected in Alternative Plan B incorporating the Company Methodology for the purposes of the future billing analysis, including forecasted sales growth, forecasted class allocation factors, and a design capacity factor for solar resources.

The typical Company residential customer in Virginia (i.e., one who uses 1,000 kilowatt-hours of electricity per month) pays $136.90 as of July 1, 2022, which on a per-unit basis is approximately 13.69 cents per kilowatt-hour ("¢/kWh"). This figure compares favorably to the national average (15.42¢/kWh) and the regional averages for the South Atlantic (13.83¢/kWh), Middle Atlantic (18.89¢/kWh), and New England (24.63¢/kWh) states as reported in the U.S. Energy Information Administration's most recent electric power monthly release using data for June 2022.

Sensitivity Analyses

The Company conducted several sensitivities for this 2022 Update to show the potential paths forward under different future conditions consistent with SCC and NCUC requirements. For all sensitivities, the Company re-optimized the build plans applying different assumptions.

First, the Company conducted sensitivities related to RGGI based on the uncertainty discussed in ***Federal Carbon Regulation***. The base assumptions for Alternative Plans A through E all use a commodity price forecast that assumes Virginia exits RGGI before January 1, 2023. For its sensitivity analyses, the Company used a commodity price forecast that assumes Virginia stays in RGGI and includes a RGGI-related cost adder on all Virginia carbon-emitting generators. Figure 2.6.1 compares the Alternative Plans under their base case assumptions with the Alternative Plan assuming Virginia stays in RGGI. As the table shows, it would be more expensive for customers if Virginia remains in RGGI, while making essentially no difference in the Company's carbon emissions other than in Plan A.

Figure 2.6.1:
2022 Update Sensitivities on Virginia in RGGI

Plan	NPV Total ($B)		Approximate CO_2 Emissions from Company in 2047 (Metric Tons)	
	Base Plan	Va. in RGGI	Base Plan	Va. in RGGI
Plan A	$68.1	$71.6	18.9	17.0
Plan B	$83.7	$85.9	5.1	5.0
Plan C	$77.2	$79.4	4.9	4.9
Plan D	$88.9	$90.9	0	0
Plan E	$88.1	$90.1	0	0

Second, the Company conducted sensitivities using different load forecasts. As discussed above, Alternative Plan B utilizes the 2022 PJM Load Forecast. The Company increased and decreased the 2022 PJM Load Forecast by 5% to show the build plans under high and low load forecast scenarios. The Company also ran a sensitivity using the 2022 Company Load Forecast. Finally, the Company ran a sensitivity reflecting only approved energy efficiency programs as required by the SCC. Figure 2.6.2 shows the results of these sensitivities.

Figure 2.6.2: 2022 Update Sensitivities on Load Forecast

	Plan B (PJM Load Forecast)	Plan B with PJM High Load Forecast	Plan B with PJM Low Load Forecast	Plan B Company Load Forecast	Plan B Existing Energy Efficiency
NPV Total ($B)	$83.7	$93.3	$79.3	$85.7	$84.2
Approximate CO_2 Emissions from Company in 2047 (Metric Tons)	5.1 M	5.4 M	5.2 M	5.2 M	5.1 M
Solar (MW)	13,692 15 yr. 25,692 25 yr.	13,692 15 yr. 25,692 25 yr.	13,692 15 yr. 25,692 25 yr.	13,692 15 yr. 25,692 25 yr.	13,692 15 yr. 25,702 25 yr.
Wind (MW)	2,600 15 yr. 2,600 25 yr.	2,600 15 yr. 2,600 25 yr.	2,600 15 yr. 2,600 25 yr.	2,680 15 yr. 2,680 25 yr.	2,600 15 yr. 2,680 25 yr.
Storage (MW)	2,620 15 yr. 3,070 25 yr.	2,620 15 yr. 4,060 25 yr.	2,620 15 yr. 2,620 25 yr.	2,620 15 yr. 2,710 25 yr.	2,620 15 yr. 3,220 25 yr.
Nuclear (MW)	— 15 yr. 1,140 25 yr.	— 15 yr. 1,995 25 yr.	— 15 yr. — 25 yr.	— 15 yr. 1,425 25 yr.	— 15 yr. 1,140 25 yr.
Retirements (MW)	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.

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

Figure 2.6.3: 2022 Update Sensitivities on NPV Costs

Plan Description	NPV Total ($B)
Plan B	$83.7
Plan B: High Fuel Prices	$93.2
Plan B: Low Fuel Prices	$83.6
Plan B: High Capital Construction Costs	$87.2
Plan B: Low Capital Construction Costs	$80.2
Plan B: Solar Design Capacity Factor	$83.2

Portsmouth Marine Terminal for Offshore Wind Project

Natural Gas pipeline installation

Short-Term Action Plan

Dominion Energy employee working at the VCEA Pilot Projectt

The short-term action plan provides the Company's strategic plan for the next five years (2022 to 2027). 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 its clean energy goals while continuing to provide safe and reliable service to its customers.

Generation

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

- File annual plans for the development of solar, onshore wind, and energy storage resources consistent with the requirements established by the VCEA, including related requests for approval of certificates of public convenience and necessity and for prudence determinations related to PPAs;
- Leverage experience with the Coastal Virginia Offshore Wind demonstration project to continue development and begin construction of the Coastal Virginia Offshore Wind commercial project with a target in-service date of 2026;
- Meet its targets under Virginia's mandatory RPS Program at a reasonable cost and in a prudent manner, and submit its annual compliance certification to the SCC beginning in 2022;
- Meet its target under North Carolina's renewable energy portfolio standard at a reasonable cost and in a prudent manner, and submit its annual compliance report and compliance plan to the NCUC;
- Support ongoing NRC review of the subsequent license renewal application for North Anna Units 1 and 2;
- Continue to make investments at existing generation units needed to comply with environmental regulations; and
- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements.

Appendices 3A and 3B provide further details on each generation project under construction and under development, respectively.

Demand-Side Management

The Company continues to identify and propose new or revised DSM programs that meet the requirements of the Grid Transformation and Security Act of 2018 ("GTSA") and the requirements and targets of the VCEA in conjunction with the established DSM stakeholder process. The Company also completed a market potential study in September 2021 and a long-term DSM plan in December 2021.

In Virginia, the Company filed its Phase X DSM application in December 2021 seeking approval of 10 DSM programs and review of the long-term DSM plan. The SCC issued its Final Order on this application in August 2022 approving the Phase X DSM programs and the reorganization and consolidation of the Company's DSM portfolio consistent with long-term DSM plan, among other approvals of the Company's requests.

In North Carolina, the Company will continue its analysis of future programs and will file for approval in North Carolina of those programs that have been approved in Virginia and 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.

Transmission

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

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

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:

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

Dominion Energy

Gaston Hydro Station; Thelma, NC

Planning Assumptions

The Company's generation planning process for this 2022 Update is consistent with the process described in Chapter 4 of the 2020 Plan. Consistent with its established process, the Company has updated its assumptions for this 2022 Update to maintain a current view of relevant markets, the economy, and regulatory drivers as of the date of this filing. The sections that follow focus on the primary input assumptions that have changed since the 2020 Plan or the 2021 Update.

Load Forecast

The 2022 PJM Load Forecast was used in the development of all Alternative Plans. Because of the limited nature of the information available from PJM and the issues discussed in ***PJM Load Forecast***, the Company also presents and discusses the 2022 Company Load Forecast and presents a sensitivity using the Company Load Forecast, shown in ***Sensitivity Analyses***.

As with the 2020 Plan and the 2021 Update, the load forecasts in the 2022 Update include a downward post-model adjustment for both energy efficiency and retail choice, as described further in ***Energy Efficiency Adjustment***, and ***Retail Choice Adjustment***, respectively.

Figures 4.1.1 and 4.1.2 compare the PJM Load Forecast with the Company Load Forecast for both 2021 and 2022. As can be seen, the 2022 PJM Load Forecast increased substantially as compared to the 2021 PJM Load Forecast.

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

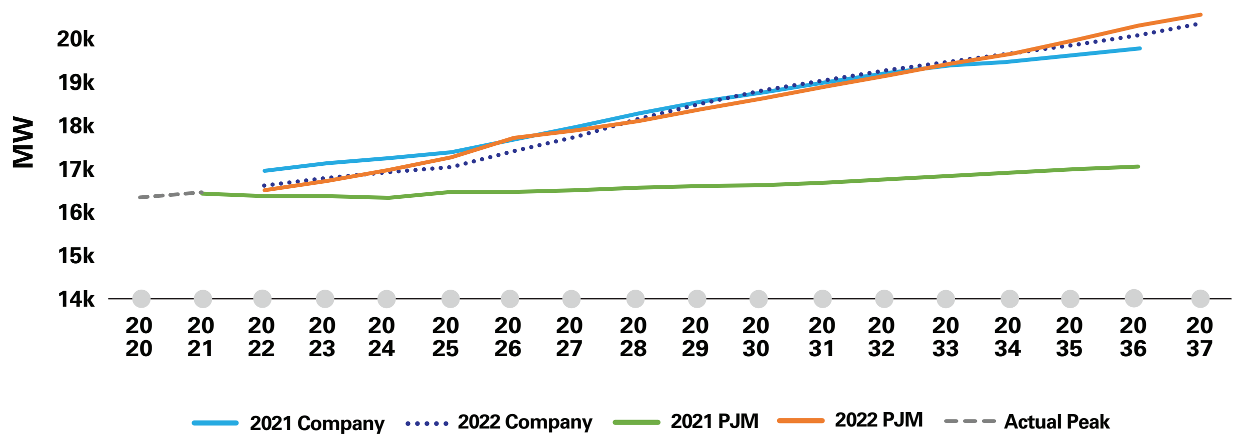
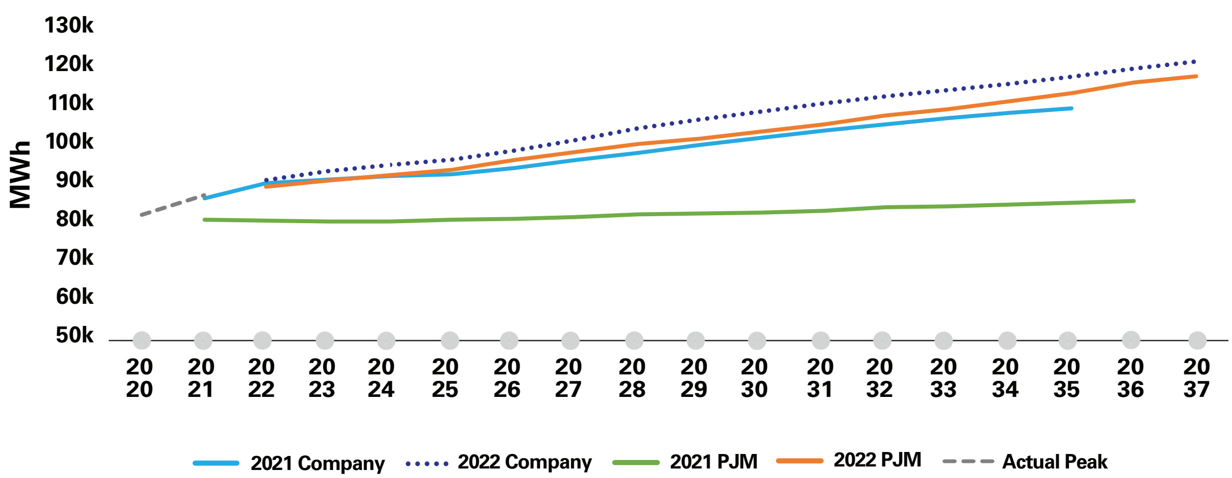


Figure 4.1.2: DOM LSE Annual Energy Comparison



PJM Load Forecast

Overall, the 2022 PJM Load Forecast (published in January 2022) anticipates that summer peak demand and energy for the DOM Zone will increase at a CAGR of approximately 2.0% and 2.9%, respectively, between 2022 and 2037. This is markedly different from the 2021 PJM Load Forecast that showed an increase at a CAGR of approximately 0.9% and 0.6%, respectively, between 2021 and 2036. The key drivers for the forecast change are addressed in ***PJM Load Forecast***.

For the 2022 Update, to arrive at the DOM LSE forecast from PJM's DOM Zone forecast, the Company used a similar methodology as in the 2020 Plan and 2021 Update with one revision related to forecast extension beyond PJM's 15-year forecast horizon. As discussed in ***PJM Load Forecast***, the 2022 PJM Load Forecast isolated the non-data center forecast from the data center forecast, and presented the data center forecast at the DOM LSE level. While non-data center peak and energy forecasts were extended based on the 15-year growth rates consistent with the methodology used in the 2020 Plan and the 2021 Update, the Company adjusted how it extended the data center forecast. Specifically, the Company extended the DOM LSE-level data center forecast using the final year annual growth rate of PJM's 15-year data center forecast. This adjustment to the methodology used to extend the 2022 PJM Load Forecast from 15 years to 25 years was made possible because PJM isolated the data center forecast for the first time. Figure 4.1.1.1 presents the adjusted 2022 PJM Load Forecast, and reflects the change to the methodology the Company used to extend the 15-year forecast to 25 years. The resulting summer peak demand and energy CAGRs are 1.4% and 1.7%, respectively, between 2022 and 2047.

PJM considers the DOM Zone to be a winter peaking zone. In other words, the winter peak demand forecast for the DOM Zone exceeds the summer demand peak in all years of the forecast period, according to PJM. Given that the PJM regional transmission organization is still a summer peaking entity, however, PJM will continue to procure capacity for the DOM Zone at levels commensurate with the DOM Zone coincident summer peak forecast. As such, the Company developed this 2022 Update using a summer peak to align with PJM's DOM Zone summer coincident peak demand and energy forecast.

Figure 4.1.1.1:
2022 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)
2022	19,890	16,056	113,160	88,612
2023	20,418	16,220	118,859	90,010
2024	21,128	16,446	125,595	91,557
2025	21,977	16,770	132,352	92,903
2026	22,743	17,178	139,354	95,328
2027	23,008	17,331	142,817	97,295
2028	23,352	17,565	146,136	99,335
2029	23,692	17,809	148,623	100,807
2030	24,001	18,030	151,408	102,497
2031	24,414	18,336	154,427	104,367
2032	24,697	18,532	158,003	106,655
2033	25,060	18,793	160,628	108,253
2034	25,356	18,999	163,762	110,230
2035	25,854	19,385	166,999	112,318
2036	26,259	19,687	170,984	114,950
2037	26,669	19,983	173,715	116,604
2038		20,208		118,273
2039		20,446		120,019
2040		20,693		121,796
2041		20,949		123,617
2042		21,211		125,482
2043		21,480		127,400
2044		21,757		129,360
2045		22,037		131,360
2046		22,332		133,404
2047		22,632		135,492

Note: For years 2038 to 2047, the Company calculated the DOM LSE forecast by adding the scaled-down non-data center forecast extended based on the 15-year growth rate with the DOM LSE-level data center forecast extended using the final year growth rate of PJM's 15-year load forecast.

Company Load Forecast

In its 2021 Update, the Company noted a few changes to its load forecasting methodology as described in Chapter 4.1.2 of the 2020 Plan. For this 2022 Update, the Company continues to provide an overview of those previous changes, plus a few additional changes made between the 2021 and the 2022 Updates.

At a high level, the Company's load forecast is prepared using DOM LSE peak and energy data, adjusted by excluding data center loads and adding back behind-the-meter solar load. This is followed by post-processing forecast adjustments for data centers, behind-the-meter solar, and EVs. Additionally, as noted above, the Company includes a downward post-model adjustment for both energy efficiency and retail choice. Figure 4.1.2.1 presents the 2022 Company Load Forecast. Overall, the Company anticipates DOM LSE summer peak demand and energy forecast CAGRs of 1.4% and 1.7%, respectively, between 2022 and 2047.

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

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

- DOM LSE peak load was derived using annual peak-to-energy ratios from the past 10 years after taking out data center load and adding back retail choice. DOM LSE is then derived using this load factor, and data center and retail choice impacts are layered on top of DOM LSE forecast. Additionally, other drivers such as EVs and DSM impacts are incorporated. Derivation of DOM LSE peak using this approach, as opposed to modeling both peak and energy independently, promotes consistency and prevents potential discrepancies between peak and energy forecasts.

- Usage per customer is modeled directly as opposed to modeling total residential sales and customer count. Residential sales are calculated as usage per customer multiplied by customer count. Modeling of usage per customer enables the Company to directly capture customer usage trends, housing characteristics, and efficiency trends embedded in historical data.

Customer Core Lineworker

- Data center sales, energy, and peak demand are being forecasted 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 recommendation provided by Itron Inc. ("Itron"), in its review of the Company's load forecasting methodology, as discussed in the 2020 Plan. The forecast utilizes a combination of a Company-prepared internal data center forecast through 2026 and an Itron data center forecast for the longer term.

- The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load. In the 2021 Update, the Company revised its EV forecasting process to incorporate a separately developed EV forecast from ICF that the Company then added to energy, peak, and sales forecast as a post-model adjustment. In this 2022 Update, the Company used an EV forecast provided by Guidehouse.[2]

[2] On August 25, 2022, the California Air Resources Board approved regulations — known as Advanced Clean Cars II— that provide for annual zero-emission vehicles standards beginning in 2026 culminating in a requirement for all new vehicle sales to be electric or plug-in hybrids by 2035. These regulations will become effective subject to the EPA granting a preemption waiver, and the resolution of any associated legal challenges. Legislation passed by the Virginia General Assembly as part of its 2021 Special Session I requires the Virginia Air Pollution Control Board to adopt motor vehicle emissions regulations mirroring those of California. To the extent the California Advanced Clean Cars II regulations become effective, this may result in impacts not included in the 2022 Update. The Company will assess applicable regulations in future filings as necessary.

Figure 4.1.2.1: 2022 Company Load Forecast

Year	DOM LSE Summer Peak Forecast (NCP) (MW)	DOM LSE Energy Forecast (GWh)
2022	16,613	90,279
2023	16,796	92,383
2024	16,942	94,062
2025	17,044	95,344
2026	17,310	97,602
2027	17,623	100,476
2028	17,950	103,203
2029	18,265	105,467
2030	18,548	107,646
2031	18,813	109,554
2032	19,058	111,401
2033	19,298	112,923
2034	19,545	114,598
2035	19,811	116,380
2036	20,096	118,432
2037	20,378	120,169
2038	20,669	122,088
2039	20,970	124,057
2040	21,250	126,044
2041	21,564	127,987
2042	21,887	130,128
2043	22,170	131,888
2044	22,453	133,810
2045	22,734	135,433
2046	23,029	137,251
2047	23,321	139,070

Energy Efficiency Adjustment

As with the 2020 Plan and the 2021 Update, the load forecasts in this 2022 Update include a downward post-model adjustment for energy efficiency ("EE"). The EE adjustment to the forecasts can be broken down into two distinct categories. The first category ("Category 1 Programs") consists of previously approved EE programs that remain effective (i.e., that are still producing savings), along with programs that were recently approved by the SCC in Case No. PUR-2021-00247. The second category ("Category 2 Program" or "generic" EE) represents unidentified EE programs and measures designed to meet legislative directives. Specifically, the generic EE is designed to meet (i) the energy savings targets in the VCEA for 2022 through 2025; (ii) a 5% energy savings target for 2026 and beyond; (iii) the GTSA requirement to propose $870 million in EE programs by 2028; and (iv) at least 15% of EE costs allocated to programs designed to benefit low-income, elderly, or disabled individuals or veterans.

Alternative Plan A is only adjusted for the approved EE programs—the Category 1 Programs. Alternative Plans B through E include the additional adjustment for generic EE—the Category 2 Program. The Company used the same methodology and estimated cost per kilowatt-hour saved from the 2021 Update to estimate the generic EE (Category 2 Program) in this 2022 Update.

This approach to generic EE is a theoretical assumption used for modeling purposes only. The actual costs and benefits of future EE will be dependent upon many factors, including the ability of future vendors to deliver program savings at the fixed price, customer participation, and the effectiveness of the program to be administered at that price.

Figures 4.1.3.1 and 4.1.3.2 identify the EE energy and capacity adjustments to the load forecasts used in this 2022 Update, respectively.

Figure 4.1.3.1: EE Energy Forecast Adjustment

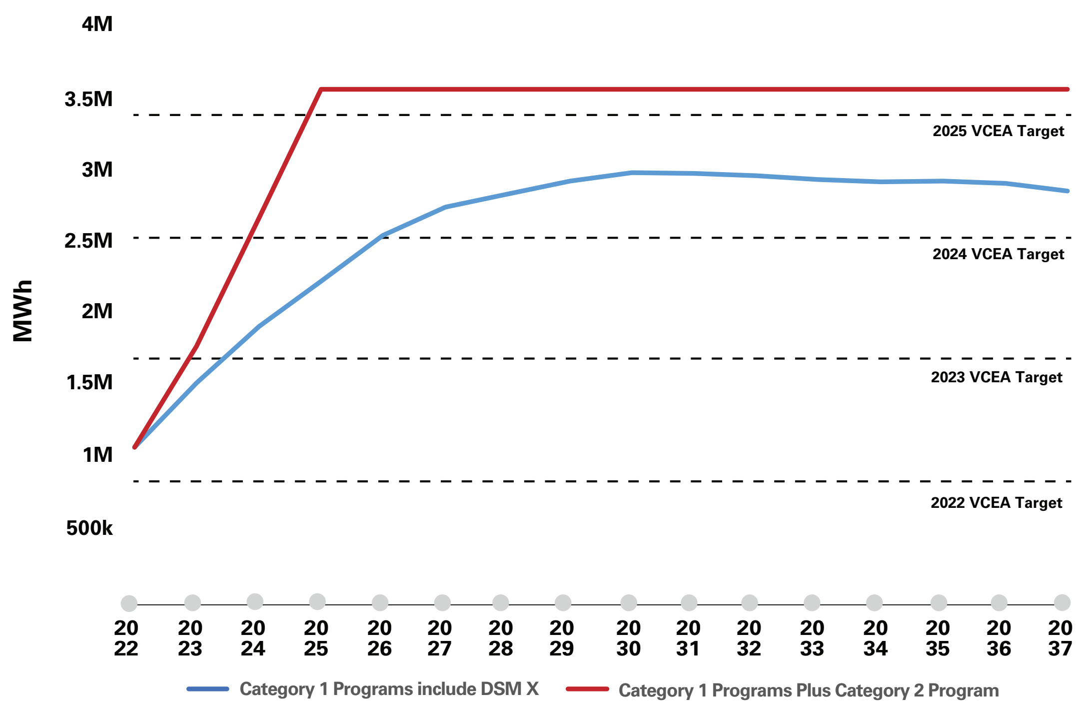
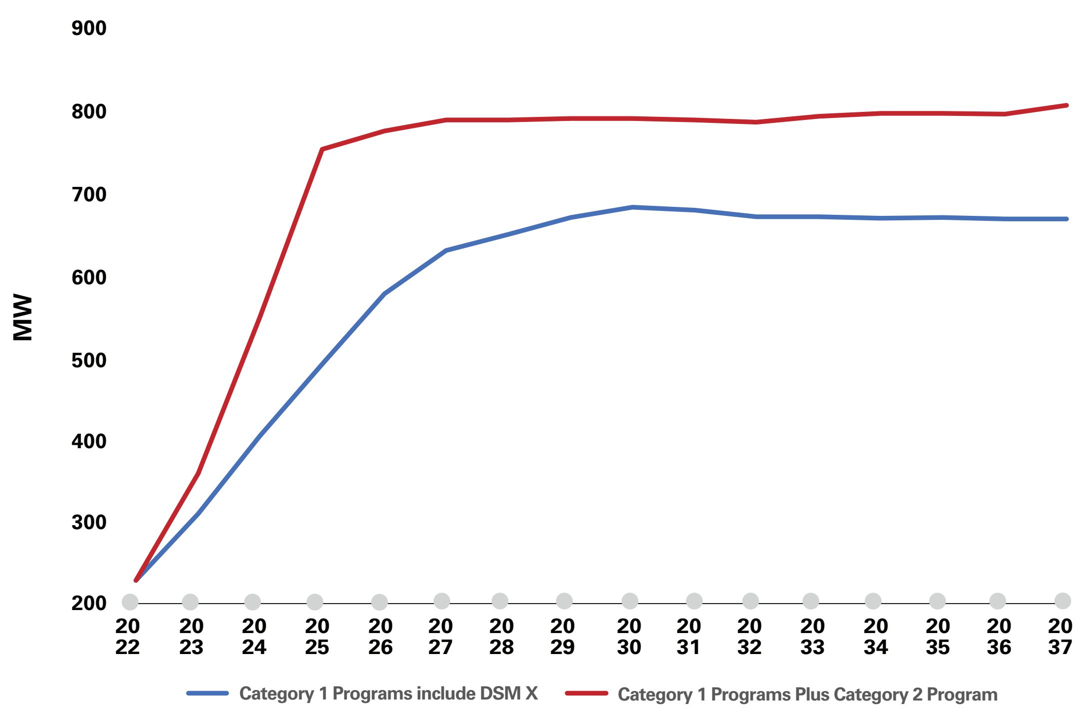


Figure 4.1.3.2: EE Coincident Summer Peak Demand Forecast Adjustment



Retail Choice Adjustment

For the 2022 Update, the Company used the same methodology described in Chapter 4.1.1 of the 2020 Plan to adjust the load forecasts for customers in the Company's service territory that have chosen (or may choose) to purchase energy and capacity from third-party electric suppliers under Va. Code § 56-577 ("Choice Customers"). The only additional assumption in the Company's calculation of future Choice Customer reduction in the 2022 Update is that the customers who elected retail choice during the year 2022 will continue to be served by a third-party electric supplier for the full year based on their actual usage history.

Capacity Value Assumptions

Since the fall of 2018, PJM has been developing a probabilistic analysis aimed at valuing the capacity value of renewable energy resources. This approach utilizes a concept called effective load carrying capability ("ELCC"). As defined by PJM, ELCC is a measure of the additional load that a particular generator of interest can supply without a change in reliability.

ELCC can also be defined as the equivalent MW of a traditional generator that results in the same reliability outcome that a particular generator of interest (such as an intermittent generator) can provide. The metric of reliability used by PJM is loss-of-load expectation, a probabilistic metric that is driven by the timing of high loss-of-load probability hours. Therefore, PJM states that a resource that contributes a significant level of capacity during high-risk hours will have a higher capacity value (i.e., a higher ELCC) than a resource that delivers the same capacity only during low-risk hours. "High-risk hours" are those hours during which PJM expects the peak demand to occur.

For the purposes of the 2022 Update, the Company utilized the December 2021 PJM ELCC study to estimate the capacity value of solar, wind, and storage resources, which is the most recently available guidance from PJM. This approach indicated the capacity value of tracking solar is currently in the 54% range, decreasing over time as solar saturation grows. For offshore wind, the capacity value is currently in the 40% range, and decreases over time as offshore wind saturation grows. This is an increase from the value of 27% used in the 2021 Update. For energy storage, the Company is utilizing a starting capacity value of 83% for four-hour systems and 100% for eight-hour systems. PJM currently performs its ELCC calculations at the hourly or daily level. PJM publishes ELCC values for these resource types for a ten-year period into the future through 2032; beyond 2032 the Company used projected ELCC values provided by ICF for the remainder of the study period.

Commodity Price Assumptions

The Company utilizes a single source—ICF—to provide multiple scenarios for the commodity price forecasts to ensure consistency in methodologies and assumptions. The Company used the same methodology to blend the ICF commodity forecasts with forward market prices for certain commodities, as described in Chapter 4.4 of the 2020 Plan. The key assumptions on market structure and the use of an integrated, internally consistent fundamentals-based modeling methodology remain consistent with those utilized in the prior years' commodity forecasts.

In the 2022 Update, the Company utilized four commodity forecasts:

- Base Case
- Base Case + VA in RGGI
- High Fuel Price
- Low Fuel Price

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

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

In the Base Case and the High and Low Fuel Price commodity forecasts, the CO_2 price forecast incorporates the assumption that Virginia exits RGGI before January 1, 2023, and that a federal carbon tax begins in 2026. This assumption regarding a federal carbon tax is consistent with the assumption used in the 2020 Plan and the 2021 Update. The Base Case + VA in RGGI assumes that Virginia remains a member of RGGI and that a federal carbon tax begins in 2026.

The Company used the Base Case commodity forecast for all Alternative Plans, which assumes that Virginia exits RGGI before January 1, 2023. The remaining three commodity forecasts were used to run sensitivities, which are described in ***Sensitivity Analyses***. Appendix 4O provides the annual prices (in nominal dollars) for each commodity price forecast. Figure 4.3.1 provides a comparison of the four commodity forecasts in this 2022 Update with the base commodity forecast used in the 2021 Update.

Figure 4.3.1: 2021 Update vs. 2022 Update Fuel, Power, and REC Price Comparison

	2022-2036 Average Value (Nominal $)	2023-2037 Average Value (Nominal $)			
Fuel Price	**2021 RGGI + Fed CO_2 Case**	**Base Case**	**High Fuel Price Case**	**Low Fuel Price Case**	**Base Case + VA in RGGI**
Henry Hub Natural Gas ($/MMbtu)	3.61	3.90	6.62	3.70	3.89
Zone 5 Delivered Natural Gas ($/MMbtu)	3.18	3.68	6.40	3.49	3.68
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	62.94	73.60	74.24	73.54	73.60
1% No. 6 Oil ($/MMbtu)	9.91	10.95	12.04	10.17	10.95
Electric and REC Prices					
PJM-DOM On-Peak ($/MWh)	35.11	43.91	65.20	42.85	44.51
PJM-DOM Off-Peak ($/MWh)	30.46	36.34	54.38	35.38	36.66
PJM Tier 1 REC Prices ($/MWh)	9.84	13.59	8.96	16.90	13.87
VA REC Prices[1] ($/kW-yr)	N/A	14.89	8.24	18.18	15.08
RTO Capacity Prices ($/kW-yr)	64.98	51.42	44.72	51.68	51.29

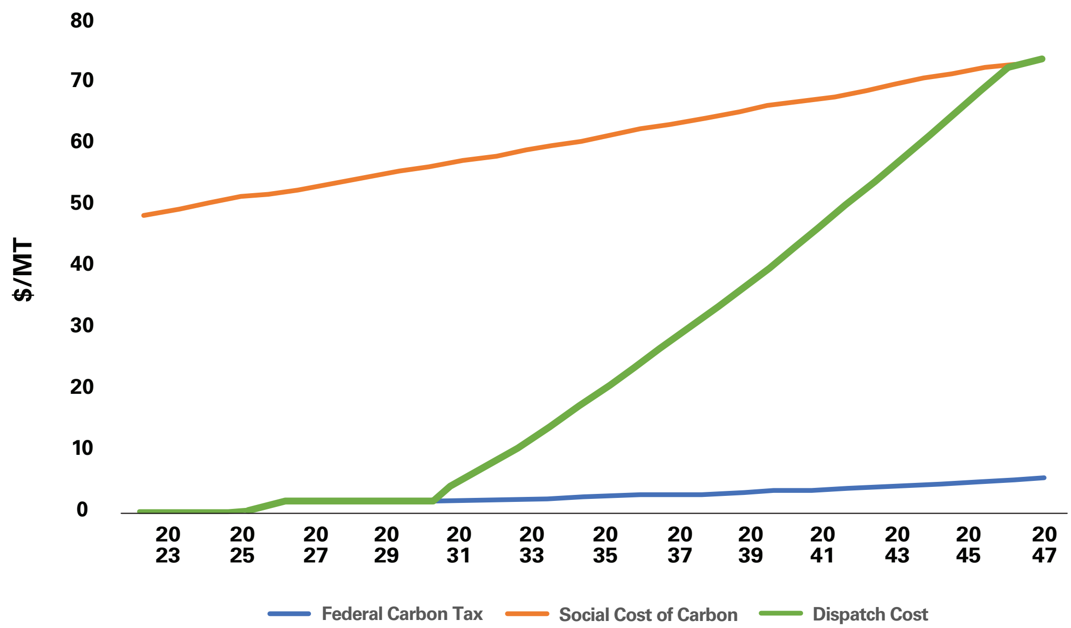
Note: (1) Reflects the ICF forecasted price for the entire period, rather than blending the ICF forecast with the market price as described in Chapter 4.4 of the 2020 Plan.

Social Cost of Carbon

The social cost of carbon is an estimate in dollars of the economic damages that result from emitting one ton of carbon into the air. The Company incorporated the social cost of carbon into its long-term planning process for the first time in the 2021 Update and followed the same approach in this 2022 Update.

Specifically, the Company includes the social cost of carbon as an indirect cost of carbon emissions. This indirect cost was included in addition to any direct cost of carbon generated by the market based on the relevant assumption regarding carbon regulations, as discussed in ***Commodity Price Assumptions***. The green line in Figure 4.4.1 depicts the dispatch carbon price included in PLEXOS.

Figure 4.4.1: Carbon Dispatch Price



As shown in Figure 4.4.1, the Company included a carbon dispatch adder equal to the forecasted price of a direct federal carbon tax in 2026 through 2030. Starting in 2031, the Company then blended the forecasted social cost of carbon with the federal carbon tax through 2046. For example, 2031 included a carbon dispatch adder of which the social cost of carbon comprised 6.7%, 2032 included a dispatch adder of which the social cost of carbon comprised 13.3%, and so on. In 2046 and beyond, the Company included a carbon dispatch adder equal to the forecasted social cost of carbon. See the 2021 Update for an explanation of why the Company employed this blended approach.

Adding the social cost of carbon as an indirect cost, or "shadow price," results in the Company's carbon-emitting generating units operating less often, thus lowering projected carbon emissions from the Company's system. Nevertheless, these units remain available to ensure system reliability. Because the social cost of carbon is an indirect cost, these costs were not included in the NPV of the Alternative Plans; only costs related to the direct carbon tax were included in the NPV results.

The Company's analysis incorporating the social cost of carbon into its long-term planning process will continue to evolve over time. For example, like the 2021 Update, the 2022 Update includes the social cost of carbon only as a cost for carbon-emitting generating units—not as a benefit for carbon-free generating facilities such as solar, wind, and nuclear. That said, the Company will include the social cost of carbon as a benefit in future applications for new clean energy generating facilities, as required by the VCEA. The Company will revise this analysis as needed in future filings.

Renewable Energy-Related Assumptions

The Company incorporated assumptions related to future renewable energy resources consistent with prior SCC and NCUC orders. The following sections detail the key assumptions used.

Solar Capacity Factor

For Alternative Plans A through E, the Company assumed a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia. Specifically, a capacity factor of 22.5% for solar tracking resources and 20.1% for solar fixed tilt resources was generally used, which represent the average capacity factors of Company-owned solar tracking and fixed-tilt facilities in Virginia for the most recent three-year period (i.e., 2019, 2020, 2021), as required by prior SCC orders. For specific resources with a design capacity factor below the applicable three-year average, the Company modeled that resource at the design capacity factor.

The Company also ran a sensitivity on Alternative Plan B using a projected design capacity factor of 24.8% for future solar resources instead of the three-year historical average capacity factor. The projected design capacity represents an average capacity factor over the life of the facility (i.e., not just three years), considering degradation. The results of that sensitivity can be seen in ***Sensitivity Analyses.***

New Solar Resources

In all Alternative Plans, the Company limited the model to selecting a maximum of 1,200 MW of utility-scale solar per year, which is based on an assumed amount of new solar generation available each year. For solar resources in Alternative Plan A, the Company allowed the model to select either Company-owned cost-of-service solar or third-party PPAs. For Alternative Plans B through E, the Company modeled solar PPAs as 35% of the solar generation capacity placed in service over the Study Period in accordance with the VCEA, which is consistent with the 2020 Plan and the 2021 Update.

New Offshore Wind Resources

In August 2022, the Company received approval of the Coastal Virginia Offshore Wind commercial project ("CVOW"), which represents nearly 2,600 MW of clean energy. CVOW is thus included in all Alternative Plans in this 2022 Update. The Company modeled CVOW using a 42% capacity factor, a 30-year life, and updated ELCC capacity values for offshore wind as discussed in ***Capacity Value Assumptions.*** In Alternative Plans A, C, and E, a second tranche of offshore wind is available for selection beginning in 2033, which represents the earliest commercial operation date for such a project. In Alternative Plans B and D, the Company forced the model to select the second tranche of offshore wind in 2034 to diversify its carbon-free generation sources and meet the Commonwealth's clean energy goals consistent with the timeframe specified in the VCEA.

Dominion Energy's Coastal Virginia Offshore Wind Project

New Onshore Wind Resources

Onshore wind was also made available for selection in this 2022 Update. Like offshore wind, onshore wind requires siting at specific locations to maximize the value for such facilities. With this in mind, the Company made two specific projects under development in Virginia available for selection—a 120 MW project with a net capacity factor of 36.5% and an 80 MW project with a net capacity factor of 42.4%. In addition to these two specific projects, the Company made an additional 80 MW generic onshore wind resource with a capacity factor of 39.5% available for selection once per year beginning in 2028. While the Company is interested in cost-effective onshore wind projects, the current availability of land suitable for onshore wind construction in Virginia is, and likely will continue to be, a limiting development constraint.

Renewable Energy Interconnection and Integration Costs

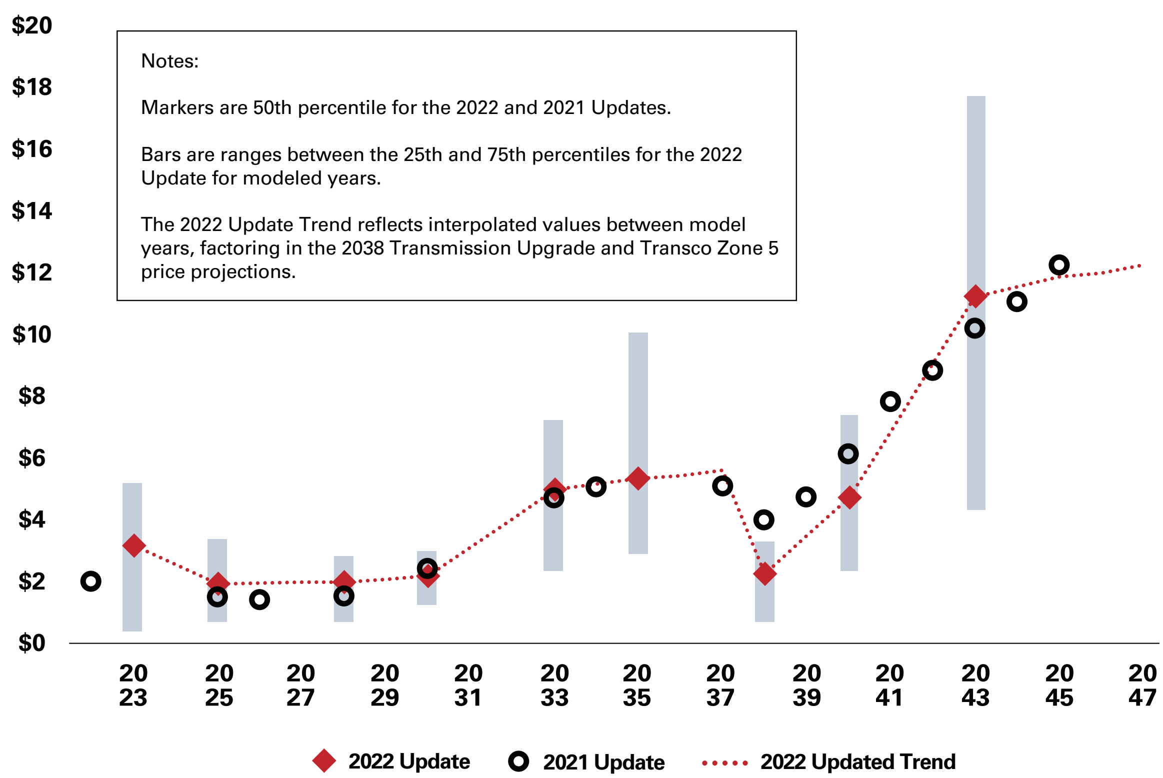
As explained in Chapter 4.6.3 of the 2020 Plan, the Company incorporates assumptions regarding interconnection costs and integration costs into its long-term planning process. In addition to integration costs, the renewable energy integration costs then include three categories (for a total of four categories) of system upgrade costs based on different issues caused by the intermittent nature of renewable energy resources: transmission integration costs; generation re-dispatch costs; and regulating reserve costs.

Interconnection Costs. In this 2022 Update, the Company assumed renewable energy interconnection costs of $138/kW for utility-scale solar facilities and $180/kW for distributed solar facilities. Consistent with the 2020 Plan and the 2021 Update, the Company assumed $0 in interconnection costs for solar PPAs because the PPA price from the developer includes interconnection costs.

Transmission Integration Costs. For transmission integration costs, the Company used the same methodology as in the 2020 Plan, updated to reflect the updated assumptions for interconnection costs noted above.

Generation Re-dispatch Costs. As explained in the 2020 Plan, re-dispatch generation costs are defined by the Company as additional costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. For the 2021 Update, improvements from the 2020 Plan were made to the variations on hourly generations to include solar and offshore wind generation, as well as to the unit commitment methodology. The methodology utilized in this 2022 Update is consistent with the 2021 Update. Figure 4.5.5.1 shows the generation re-dispatch costs incorporated into the 2022 Update.

Figure 4.5.5.1: Generation Re-dispatch Cost Results ($/MWh)



Regulating Reserve Costs. As described in the 2020 Plan, regulating reserves are defined as additional reserves needed to balance the uncertainty of forecast errors of net load that occur during a typical power system operational day. The methodology utilized in this 2022 Update is consistent with the 2020 Plan and the 2021 Update, with the analysis update based on current market information. Figure 4.5.5.2 shows the net cost to customers for regulating reserves incorporated in this 2022 Update.

Figure 4.5.5.2: Company Net Regulating Reserves Cost of Market Purchases ($000,000)

Year	Plan A	Plan B	Plan C	Plan D	Plan E
2023	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0
2029	$0	$0	$0	$0	$0
2030	$0	$0	$0	$0	$0
2031	$10	$0	$0	$0	$0
2032	$39	$0	$24	$0	$0
2033	$68	$0	$52	$0	$0
2034	$61	$0	$81	$0	$0
2035	$54	$0	$111	$0	$0
2036	$46	$0	$143	$0	$0
2037	$77	$0	$175	$0	$0
2038	$70	$21	$187	$43	$40
2039	$102	$52	$201	$63	$60
2040	$136	$85	$215	$76	$73
2041	$129	$119	$400	$118	$115
2042	$164	$330	$416	$132	$129
2043	$201	$369	$433	$396	$214
2044	$239	$411	$452	$417	$231
2045	$277	$437	$468	$547	$518
2046	$318	$455	$486	$570	$541
2047	$359	$473	$505	$594	$22

Note: Zero values indicate that the DOM LSE has adequate regulating reserves to supply reserve requirements from the LSE's load and renewable generation portfolio that year.

REC-Related Assumptions

Through 2024, for each Alternative Plan, the Company allowed the model to select 100% of RECs for Virginia RPS Program compliance as purchased from a PJM REC market and assumed that all RECs produced by Company-owned or contracted resources located in Virginia were banked for future use. Beginning in 2025, the Company allowed the model to select 25% of RECs as purchases from a PJM REC market and 1% of RECs for RPS Program compliance as purchases from a Virginia REC market for the remainder of the Study Period. See ***Virginia REC Market***, for a discussion of the Company's rationale for these assumptions.

Unlike the 2021 Update, none of the five Alternative Plans in the 2022 Update show RECs in excess of the annual Virginia RPS Program requirement because of the higher 2022 PJM Load Forecast. Accordingly, the only REC banking that the Company needed to account for in the 2022 Update related to timing resulting from the Company's strategy to bank RECs from Virginia-sited facilities through 2024 ahead of the in-state REC requirement beginning in 2025. To account for this, the Company incorporated into the NPVs for each Alternative Plan the cost of REC purchases from a PJM REC market in 2023 and 2024 to meet the Company's compliance obligations in those years and then subtracted the value of banked Virginia RECs in 2025 and 2026.

The Company also included its Virginia Schedule 19 PPAs with long-term REC contracts as reductions to the overall RPS Program requirement in all Alternative Plans. The Company identified four solar facilities from which the Company purchases a bundled product comprised of capacity and energy through a Schedule 19 PPA and RECs through a long-term contract. Two of these facilities were included in the behind-the-meter reductions during the PJM load forecast development process; accordingly, the Company did not model these facilities in PLEXOS. Instead, the capacity and energy of these facilities are assumed to be reflected in the 2022 PJM Load Forecast while the RECs were accounted for by reducing the annual Virginia RPS Program requirement by the amount of RECs (as measured by generation) that these units will provide annually. The other two facilities are not behind-the-meter, so were included in the PLEXOS model directly; these facilities are in the "Existing Generation" category on the capacity, energy, and REC charts shown in ***Capacity, Energy, and REC Positions***.

Least-Cost Plan Assumptions

Alternative Plan A presents a least-cost plan using assumptions required by the SCC. Specifically, Plan A uses the 2022 PJM Load Forecast adjusted for only existing and proposed energy efficiency consistent with prior SCC orders. It meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA; see ***RGGI*** and ***Commodity Price Assumptions***, for the Company's assumptions regarding "applicable carbon regulations." For Plan A, the Company did not force the model to select any specific resources and did not exclude any reasonable resource options. Consistent with this directive from prior orders, the Company did not exclude carbon-emitting resources as an option to reliably meet customers' energy and capacity needs. PLEXOS also included reasonable build constraints, including the 1,200 MW annual solar limit. The potential unit retirements shown in Plan A are those selected by PLEXOS without regard for other factors that the Company considers when evaluating unit retirements, as discussed further in ***Existing Supply-Side Generation***.

PLEXOS Modeling Refinements

As noted in the 2021 Update, the Company has included several refinements to PLEXOS since the 2020 Plan to incorporate the many requirements of the VCEA, including a dynamic RPS Program requirement based on forecasted customer sales; the ability to purchase RECs from eligible market sources to satisfy portions of the Company's RPS Program requirements; deficiency payment logic; adjustments for excess RECs; and optimized generating unit retirement logic for least-cost modeling. In this 2022 Update, the Company made the following modeling refinements:

- Included a declining cost curve for solar and storage unit capital costs consistent with the 2021 NREL annual technology baseline assumptions for the moderate scenario, as discussed in ***Commodity Price and Cost Assumptions***;

- Modeled distributed solar and all energy storage as combination units that reflect the costs of 65% Company-owned resources to 35% PPAs, consistent with how utility-scale solar was modeled in the 2021 Update;

- Re-optimized the model for the cost sensitivities presented in Figure 2.6.3, rather than locking down the base case build plan;

- Modeled named solar units at the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia; and

- Included the options to purchase RECs from a Virginia REC market based on initial forecasted price assumptions received from ICF.

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

VCEA Pilot Project

Generation – Supply-Side Resources

North Anna Hydro Power Plant

This chapter provides an overview of the Company's existing supply-side generation and the Company's analysis of future supply-side generation to the extent that there have been changes from the 2020 Plan and the 2021 Update.

Existing Supply-Side Generation

Appendix 5A provides information on the Company's existing supply-side resources. The Company continuously evaluates various options with respect to its existing fleet, while staying cognizant of environmental regulations and other policy considerations.

Similar to the 2021 Update, for this 2022 Update the Company updated its retirement analyses consistent with its prior practice and SCC orders. First, the Company completed a 10-year cash flow analysis focused on coal-fired, biomass-fired, and large combined cycle generation facilities under market conditions. Similar to prior Plans, the Company evaluated 10-year cash flows under five scenarios using the Base Case commodity price forecast as an underlying market forecast. Unit NPVs were derived by comparing the unit costs, including operations and maintenance and capital, to the total forecasted unit benefits, consisting of energy and capacity revenues (and REC revenues where applicable) for the next 10 years based on the snapshot in time when the analysis was conducted. This analysis allows the Company to view each unit's near-term projected revenue and cost streams in one place, and to determine key drivers for unit profitability.

A positive NPV result indicates that the unit is currently better than market, while a negative value indicates the unit is currently worse than market. These results alone are not comprehensive and cannot exclusively be used to determine whether to continue to operate an existing unit. Other quantitative and qualitative considerations must be prudently factored into such determinations, such as remaining useful life, capacity and energy replacements, system reliability, fuel contracts, transmission system considerations, personnel, impact of continued operation of the unit(s) on the local economy, and environmental benefits, to name a few. The results of the 10-year cash flow analysis are included in Figure 5.1.1.

Figure 5.1.1: Ten-Year Cash Flow Analysis Results (NPV $ Million)

Units	2022 Plan A	Low Capacity Price	High Capacity Price	2022 Plan B	Plan B High Fuel	Est. T&D Impact
Clover 1 - 2	$23	($12)	$66	$22	$116	$0
Mt. Storm 1 - 3	($23)	($175)	$162	($32)	$526	$60
VCHEC	($58)	($115)	$11	($63)	$173	$20
Altavista	($46)	($50)	($41)	($46)	($35)	$0
Hopewell	($41)	($45)	($36)	($41)	($32)	$0
Southampton	($39)	($44)	($34)	($39)	($29)	$5
Rosemary	$4	($10)	$22	$4	$4	$30
Bear Garden	$357	$295	$431	$344	$346	$30
Brunswick	$896	$760	$1,063	$866	$877	$60
Chesterfield 7 - 8	$167	$129	$214	$157	$136	$80
Gordonsville 1 - 2	$61	$39	$87	$57	$53	$71
Greensville	$1,329	$1,175	$1,518	$1,291	$1,312	$71
Possum Point 6	$194	$137	$263	$186	$190	$334
Warren	$1,003	$868	$1,169	$973	$949	$250

Note: The High and Low Capacity Price scenarios used Plan A's underlying assumptions. "Est. T&D Impact" represents the approximate transmission and distribution upgrades that would be necessary to support the unit retirement. This avoided cost is not included in the NPVs shown.

Second, as directed by the SCC, the Company included the same unit-specific data for the units listed in Figure 5.1.1 in PLEXOS to allow the model to optimize endogenously the timing of unit retirements. The Company presents these results as part of Alternative Plan A, which shows Altavista, Hopewell, Southampton, and Virginia City Hybrid Energy Center ("VCHEC") retiring in 2024 and all other units running through the Study Period.

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

VCHEC entered commercial operation in July 2012 and is designed to burn coal, waste coal, and biomass. In addition to serving customers' energy and capacity needs, VCHEC supports jobs, economic development, and water quality improvements in the coalfield regions of Virginia. Based on these qualitative factors, the retirement of VCHEC was modeled in 2045 in Alternative Plans B through E, which is consistent with the VCEA-specified retirement date for VCHEC. Altavista, Hopewell, and Southampton serve customers' energy and capacity needs while also producing RECs and production tax credits. In the short term, these biomass units supply renewable energy for the Company's 100% renewable energy tariff (i.e., Rate Schedule TRG), help the Company transition to a cleaner energy fleet, and support their local economies, such as the logging and trucking industries. Based on these factors, the retirement of the three biomass units was modeled in 2028 in Alternative Plans B through E, which is consistent with the VCEA-specified retirement date for biomass.

As noted in the 2020 Plan and the 2021 Update, the Company anticipates retiring Yorktown Unit 3 and Chesterfield Units 5 and 6 in 2023. The Company has not made any decision regarding the retirement of any generating unit other than Yorktown Unit 3 and Chesterfield Units 5 and 6. Accordingly, the inclusion of a unit retirement in this 2022 Update should be considered as tentative, based only on a snapshot in time. The Company's final decisions regarding any unit retirement will be made at a future date. Appendix 5J lists the generating units considered for potential retirement.

Future Supply-Side Resources

The Company followed a similar process for selecting alternative resource types as described in Chapter 5.5 of the 2020 Plan.

Supply-Side Resource Options

Figure 5.2.1.1 summarizes the resource types that the Company reviewed as part of this 2022 Update. Those resources considered for further analysis in the busbar screening model and PLEXOS are identified in the final columns.

Figure 5.2.1.1: Alternative Supply-Side Resources

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

Prior Plans provided details on the technologies listed in Figure 5.2.1.1., ***Small Modular Reactors***, provides more information on advanced nuclear technologies. See below for an update on energy storage.

Energy Storage. The term "energy storage" applies to a diverse set of technologies that can store energy at one time and make it available at another time. The technologies range in size, cost, performance characteristics, and application. Energy storage can support the grid in several ways, including improved reliability, increased resiliency, and operational flexibility.

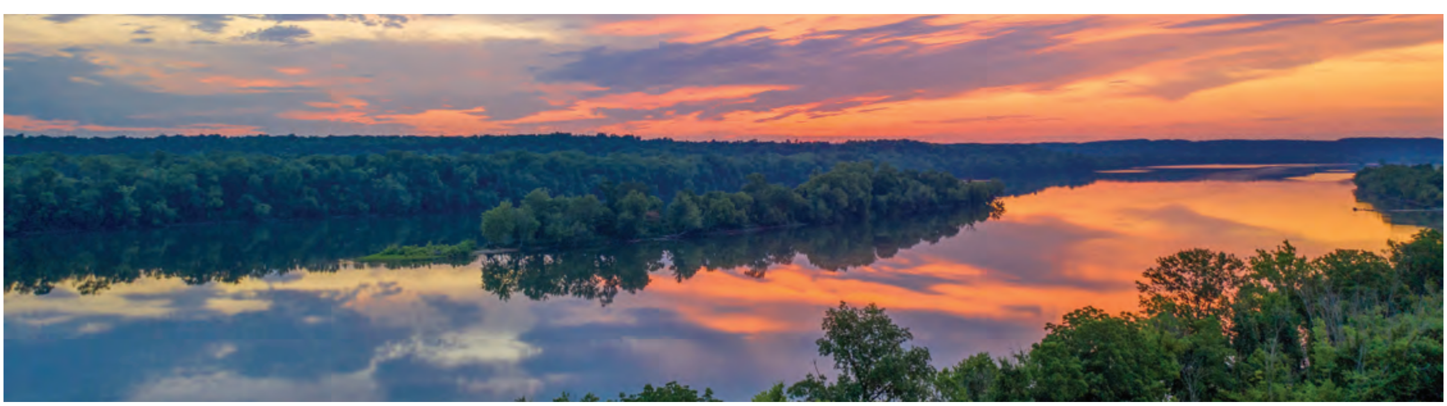
Until recently, energy storage resources have not been broadly deployed at utility scale, other than pumped hydroelectric storage. In addition to legislation in recent years supporting pumped storage, the GTSA established a pilot program to test different applications of storage, and the VCEA sets targets for the development of energy storage generally in Virginia to enhance the reliability and performance of the generation and distribution systems.

The Company has two BESS currently operational that were approved by the SCC under the GTSA pilot program, one to study solar plus storage and one to study the prevention of solar back-feeding onto the transmission grid at a specific substation. The Company expects a third BESS to become operational in the third or fourth quarter of 2022, which will be used to study storage as a non-wires alternative to reduce transformer loading at a specific distribution substation. The Company will file with the SCC its first annual report on the pilot program by March 31, 2023, including lessons learned from constructing these three BESS. Separate from the GTSA pilot program, the SCC approved two storage facilities (one of which is paired with a solar facility) in March 2022 that are currently under construction.

The Company presents its plan for the development of additional energy storage resources in the annual proceeding required by Va. Code § 56-585.5, including its progress to date on energy storage development. As stated in those plans, the Company intends to pursue additional energy storage resources, including opportunities to use energy storage for peak demand reduction and non-wires alternatives. Currently, the Company is evaluating a potential project to study storage paired with direct current fast charging infrastructure for EVs and another potential project aimed at understanding the ability of storage to provide backup power and resiliency for the Company's customers. While the Company believes that BESS (lithium-ion technology in particular) will be the dominant form of energy storage for the foreseeable future, the Company will also seek opportunities to expand its understanding of energy storage technologies by evaluating additional forms of energy storage, including long duration storage technologies, and establish projects to deploy those technologies where technically and economically feasible. See SCC Case Nos. PUR-2020-00134, PUR-2021-00146, and PUR-2022-00124 (forthcoming) for more information on the Company's approach to energy storage.

Levelized Busbar Analysis

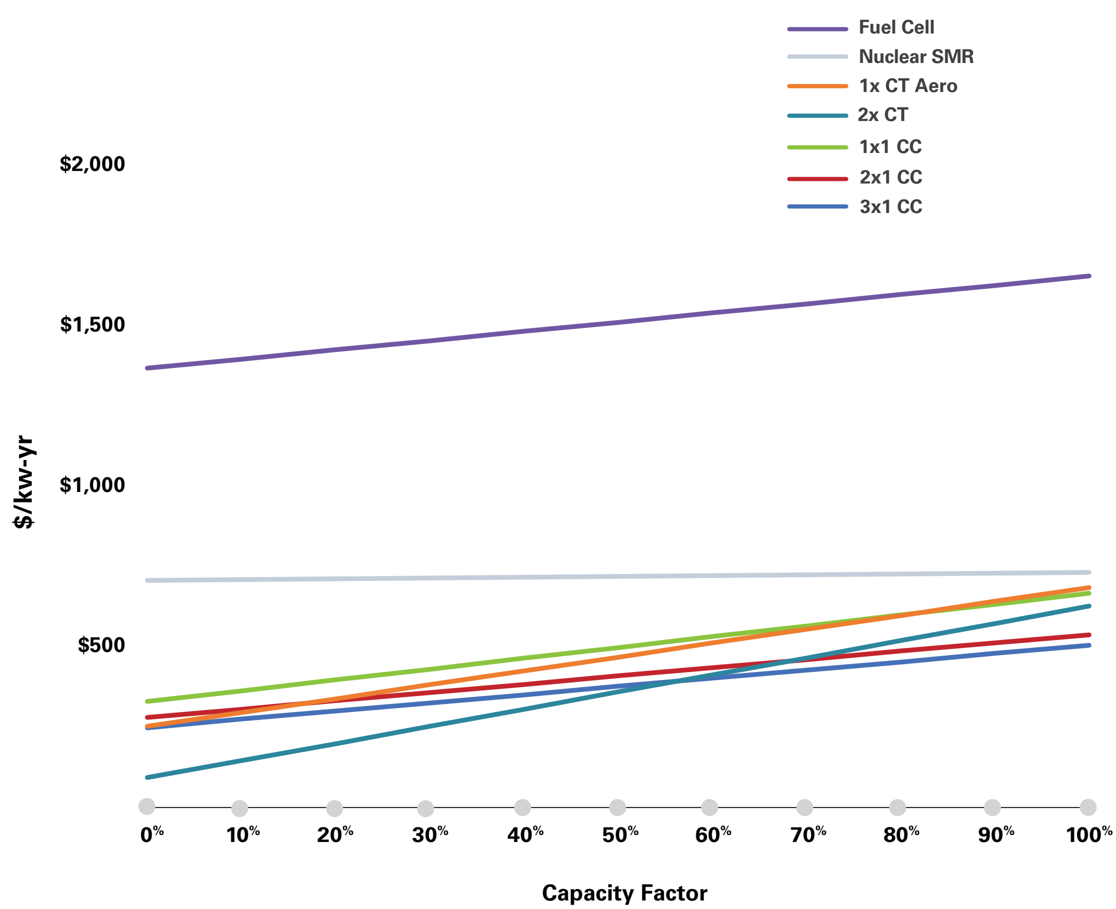
The Company's busbar model was designed to estimate the levelized energy costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include fuel, heat rate, emissions, variable and fixed operation and maintenance costs, expected service life, applicable investment or production tax credits, and overnight construction costs. These comparisons are also referred to as the levelized cost of energy or "LCOE."



Sunrise over the Potomac River

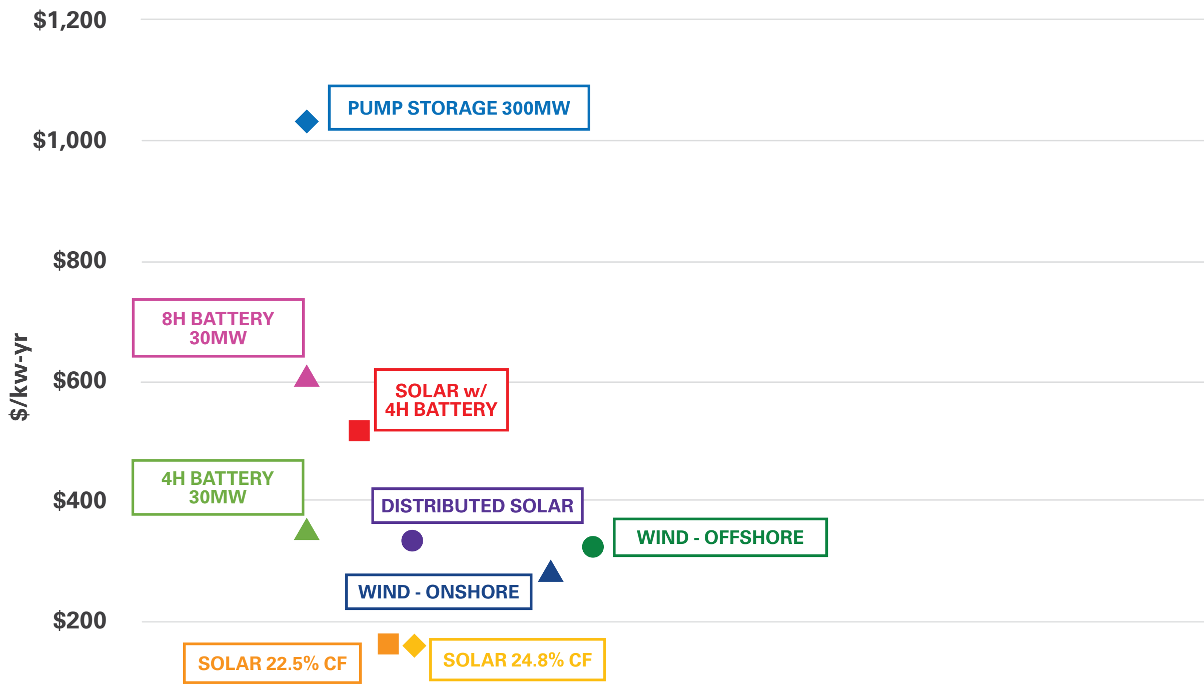
Figures 5.2.2.1 and 5.2.2.2 display high-level results of the busbar model, comparing the costs of the different technologies. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources in terms of the energy and capacity value they provide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

Figure 5.2.2.1: Dispatchable Levelized Busbar Costs (2027 COD)



Notes: "CC" = combined cycle; "CT" = combustion turbine; "SMR" = small modular reactor.

Figure 5.2.2.2: Non-Dispatchable and Energy Storage Levelized Busbar Costs (2027 COD)



Note: "8H" = eight hour; "4H" = four hour; "CF" = capacity factor.

Generation – Demand-Side Management

BrightSuite solar install

The Company's DSM planning process used for this 2022 Update is consistent with the process described in Chapter 6 of the 2020 Plan. Appendix 6A provides program descriptions for the currently active DSM programs, while Appendix 6F provides program descriptions for the recently approved DSM programs. See ***Energy Efficiency Adjustment*** for discussion of how the Company adjusted the load forecasts used in this 2022 Update to account for energy efficiency targets.

The Company's DSM planning process has also been enhanced since the 2020 Plan and 2021 Update through the development of a DSM long-term plan. In the 2020 DSM Final Order (Case No. PUR-2020-00274), the SCC directed the Company to present a long-term plan for DSM sufficient to comply with the total energy savings targets in the VCEA and investment levels in the GTSA. The SCC required that the long-term plan should include: (i) proposed program savings and budgets for the five-year period beginning January 1, 2022, sufficient to comply with the total energy savings targets in the VCEA and investment levels in the GTSA; (ii) a proposed plan and framework for consolidating, streamlining, and marketing the public-facing aspects of the Company's approved and proposed DSM programs to facilitate participation at the levels required to achieve the VCEA targets; and (iii) a detailed project management plan and risk management strategy demonstrating that the Company has identified and planned for deployment of the resources required to implement its revised programs. The SCC also required that the strategic plan should reflect short-term, medium-term, and long-term recommendations for improvement of the Company's DSM Portfolio.

In consideration of VCEA targets and discussions with DSM stakeholders, the Company decided to obtain an external industry-informed perspective to assist in developing a DSM long-term plan. Accordingly, in 2020, the Company issued an RFP for consulting, planning, and technical services in support of the Company's DSM portfolio. Cadmus was the successful bidder in this RFP process. Cadmus was charged with developing a long-term plan for DSM that could chart the Company's path over the next decade. Throughout the development of the long-term plan, Cadmus consulted with the Company, its DSM contractors, and numerous internal and external stakeholders for input and feedback.

The DSM long-term plan provides a path forward for the Company's DSM program portfolio, with the end goal of setting forth an achievable strategy for meeting the VCEA energy efficiency targets. It provides a vision and pathways for making every practicable effort to achieve the legislative goals over short-, medium-, and long-term timeframes. The long-term plan addresses strategic vision; achievability of GTSA and VCEA energy efficiency targets; risks, challenges, and opportunities stemming from legislative and regulatory changes; sector profiles, program design recommendations, and implementation pathways aligned with targets and high-level timelines; approaches for adapting to an evolving customer market and advancements in technology; and high-level forecasts of energy and demand impacts, program costs, and cost-effectiveness.

In sum, the Company expects the DSM long-term plan to be instrumental in future iterations of the DSM planning process, which will be reflected in future filings. The SCC has also issued directives regarding the evaluation, measurement, and verification of the Company's DSM programs, which will guide how energy and capacity savings influence planning projections.

For this 2022 Update, at the end of the Planning Period (i.e., 2037), energy reductions projected for all approved DSM programs are approximately 3,802 GWh. This compares to 1,586 GWh identified in the 2020 Plan and 2,643 GWh identified in the 2021 Update. The summer capacity reductions at the end of the Planning Period for all approved DSM programs are approximately 826 MW in this 2022 Update. This compares to 565 MW in the 2020 Plan and 500 MW in the 2021 Update. The majority of these changes are attributable to the recently approved Phase X DSM programs from the 2021 Virginia DSM filing and updates associated with the 2021 evaluation, measurement, and verification report, which changed the dates and times of the coincidental capacity reductions.

Air filter replacement in an HVAC unit

Customer adjusting a smart thermostat

Transmission lines and substation; Loudoun County, VA

Transmission

This chapter provides an update on the transmission system reliability analyses first discussed in the 2020 Plan. In the 2020 Plan, the Company provided an initial overview of the reliability analyses needed to investigate the probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generation facilities. This included commitments to:

- Analyze impacts associated with the loss of traditional synchronous generators, as well as the impacts of inverter-based generation at varying levels above and below their capacity factors. These impacts include the changes in system characteristics, such as inertia and frequency control, short-circuit system strength, power quality, reactive resources and voltage control, and system restoration and black start capabilities.

- Research the capabilities of inverter-based resources to provide needed system characteristics.

- Study the probability and impact of concurrent periods of generation excesses and deficits between the DOM Zone in PJM and neighboring regions.

These newer reliability studies are actively under development by the Company and include traditional reliability analyses. These traditional analyses include NERC Reliability Standard criteria and violations, PJM reliability criteria, existing Company criteria, thermal loading issues, and voltage issues. In addition to investigating these newer and traditional reliability concepts, the Company is also investigating existing and new technology solutions that may be needed to address reliability issues in the future. Existing technologies include transmission substations, transmission lines, synchronous generators, transformers, capacitor banks, reactor banks, static volt-amp reactance ("VAR") compensators, and static synchronous compensators. Some of the new technologies the Company is investigating include advanced grid monitoring and control capabilities; energy storage technologies; flexible alternative current transmission system ("FACTS") devices, such as high-voltage direct current ("HVDC"), and synchronous condensers; grid-forming inverters; high-capacity transmission substation equipment and line technology; and advanced software and computational hardware for modeling, simulations, and analytics.

Over the past year, the Company has continued to work on these long-term modeling and analysis efforts in order to ensure the future reliability and resiliency of the grid. For example, the Company has continued to develop new system models for future years, studying areas of the system with large load increases expected, evaluating new renewable energy generation interconnection projects, and developing new methodologies and tools to study the new reliability issues and concerns. The Company has also been testing new simulation software platforms and researching new grid technologies and solutions, including grid forming inverters, energy storage technology, and synchronous condensers. A summary of the Company's analyses completed for this 2022 Update is included in ***Reliability Analyses of Alternative Plans***, and the following sections.

Inertia and Frequency Response

Electrical inertia is the capacity of a system to resist changes in electrical frequency, which is the real-time balance between generation and load. Electrical inertial response acts to overcome an immediate imbalance between power supply and demand. Electrical inertia is directly related to the reservoir of stored kinetic energy inherent to the traditional rotating synchronous generators on the system. Inertia is what allows the electric grid to control the frequency deviations that occur all the time, which are caused by events such as load changes, transmission and distribution outages, generation shedding, and system instability. Inverter-based solar- and wind-powered resources have no rotating components and, as a result, typically do not contribute to system inertia. This can lead to significant problems in managing system frequency, leading to a less reliable electric grid under high penetration of inverter-based generation resources.

It is critical to examine the synchronous inertia and frequency response of the Company's system because these two criteria provide insights into the total frequency support of the power system. Both theoretical and software simulation methods have been explored to investigate which Alternative Plans can ensure an acceptable frequency support. A total of 18 dynamic models for the Company's network under different power flow conditions and Alternative Plans were created and studied. The preliminary results show a clear deterioration of inertia response as the Company's system moves away from relying on large synchronous generation. Additionally, the system's primary frequency response is suboptimal for Plans D/E following the loss of large synchronous generation. This study gives a verification of the system inertia trend. However, the fast and primary frequency response study was simplified due to present-day simulation tools' limitations and available information. Moreover, the Company did not consider the system outside of the DOM Zone to obtain a conservative result for this parameter. These results will be revisited and re-verified in future years as more information is available. The development of new technology in converter controls and modeling will be included in future studies.

Transmission lines; Loudoun County, VA

Fault Current Analysis

When power system conductors of one phase attach to or get close to another phase or the ground, a fault occurs. It is essential to detect and clear the fault in a timely manner to keep the power system stable, protect human life, and protect power system facilities. Traditional synchronous generators typically contribute six to seven times the rated current during a fault, by which the protection system can detect and clear the fault. Inverter-based resources in comparison typically contribute 1.1 to 1.2 times the rated current during a fault. Therefore, with the increased penetration of inverter-based resources and the retirement of traditional synchronous generators, the fault current is expected to decrease and could impair the effectiveness and performance of current protection systems.

The fault current change due to future synchronous generator retirements on the Company's system was analyzed. A cluster of models were developed to represent the system in different phases. In each Alternative Plan, some existing carbon-emitting generators are retired, and inverter-based resources are installed to balance the load. The results indicate that the average fault current over the system decreases proportionally to the number of synchronous generator retirements. The highest impact on fault current is then produced by Plans D/E. Furthermore, the decreased percentage on each bus varies over a wide range. Therefore, the impact of each relay may need to be treated individually. Those with significant changes of fault current may need new configuration parameters, schemes, or protection devices.

Importantly, fault current changes on the system depend on the locations of inverter-based resources. In this study, the location of future inverter-based resources connecting to the Company's system are forecasted based on historical data, and those outside of the Company's system are generally unknown. This study will be conducted periodically to track the tendency of fault current changes.

Black Start

Large-scale blackouts negatively impact the public, the economy, and the power system itself. A proper black start system restoration plan can help to restore power quickly and effectively. Black start—which restores electric power stations and the electric grid without relying on external connections—is the most critical scenario for system restoration. A black start unit is a generator that can start from its own power without the support from the power grid, which is essential in the event of a major system collapse or a system-wide blackout. Black start units, and the generation included in the system restoration plan, must be available 24/7 and must have constant and predictable output when operational. Both PJM and the Company maintain a system restoration plan. The Company has identified three key vulnerabilities to its system restoration capability that will drive the need for traditional synchronous machines.

The first has to do with the age and commercial viability of black start units in supplying timely restoration generation. The Company does not own all of the black start units in its system. Per PJM rules (see PJM Manual 14D, Section 9.1.1), black start units can opt out of black start service with one year's advance notice of deactivation. In addition, if a generation owner cannot provide black start service due to an event of force majeure, the commitment requirements are not binding. If current black start units are not available to provide black start service, the next available options are electrically more challenging and may hinder restoration of off-site power to critical load.

The second vulnerability involves the current PJM definition of critical load on which the justification for black start units is based. The PJM definition of critical load includes cranking power to all units with faster start-up times (four hours or fewer), nuclear safe shutdown loads, and electric-powered natural gas compressor station loads. This definition does not include critical load associated with command-and-control facilities, defense critical energy infrastructure, telecom systems, and data centers. Effective access to data and communication systems and safe and timely access to the Company's electric transmission equipment are integral to the Company's ability to restore the electric grid after a blackout. Current black start resources may be insufficient to meet this expanded definition of critical load.

Finally, there is a significant system reliability impact associated with interruption of natural gas supply. The recent cyber-attack on the Colonial Pipeline negatively impacted fuel supply for over a week. If a similar incident affected the ability to deliver natural gas to the Company's power generation facilities, the Company would be challenged to provide sufficient electricity to power circuits serving critical customers and may result in detrimental effects to public safety, welfare, and health.

These vulnerabilities can be addressed with the addition of quick start, flexible, dispatchable generation units. The Company plans to study these vulnerabilities related to system restoration in more detail and will provide updates in the future filings.

Other Information

Mamadou Dion, a consulting engineer for Dominion Energy

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

Seasonal Capacity and Energy Needs

As discussed in Chapter 5.6 of the 2020 Plan, when increasing amounts of solar resources are added to the system, this will result in intra-day, intra-month, and seasonal challenges posed by the interplay of solar generation and load. These challenges could expand as neighboring states increase the amount of renewable energy generation on their systems, potentially leading to higher peak prices and a reduction in the level of imports available. Appendix 2A shows the Company's capacity position under each Alternative Plan in the summer. Appendix 5T shows the Company's capacity position under each Alternative Plan in the winter.

As can be seen in Appendix 5T, Alternative Plans A through E in this 2022 Update do not always meet the winter requirements under the 2022 PJM Load Forecast. While the current PJM ELCC values increased for both wind and storage resources, the Company believes that as storage and intermittent resources become a larger percentage of the resources in PJM the ELCC will decrease in value, in which case the Company may need additional dispatchable resources to meet customers' winter requirements.

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

Environmental Justice

The Virginia Environmental Justice Act sets the policy of Virginia to promote environmental justice, ensuring the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy. The Secretary of the North Carolina Department of Environmental Quality established an Environmental Justice and Equity Advisory Board to assist the agency in achieving fair and equal treatment of all communities across the state.

The clean energy transition requires substantial development of new infrastructure, which has the potential to affect surrounding communities. Dominion Energy and the Company are committed to ensuring that those communities have a meaningful voice in planning and development processes. In cases where a community meets the definition of an environmental justice community, the Company's process requires that it consider proactive and intentional communication and engagement to ensure that concerns are appropriately responded to and addressed, and that the Company works to mitigate any undue project impacts. The Company's aim is to ensure that all communities affected by its infrastructure projects have a voice in their development, and that the Company avoids disproportionately affecting or benefiting any one group. The Company also wants all communities to have the chance to benefit from the economic opportunities presented by clean energy investments.

The Company believes that environmental justice is best evaluated on a case-by-case basis, informed by the location of the project in question and project-specific characteristics. The Company notes that environmental justice evaluations will increasingly include allocating resources that communities desire, such as underground distribution lines to promote greater reliability, access to EV charging infrastructure, and the Company's middle-mile broadband program. The Company has established an environmental justice review process for evaluating its specific projects and programs that implicate environmental justice consistent with relevant laws and regulations, as well as previously developed EPA guidance, and currently accepted best practices. The Company has begun to present the results of these project-specific review processes in the relevant proceedings before the SCC, such as its applications to construct new generating facilities or new transmission lines. By contrast, attempting to evaluate generic projects in the abstract during integrated resource planning—when resources are evaluated by capacity and type in general, without any specific project facts or location—provides limited value in the Company's view.

Economic Development Rates

As of August 2022, the Company has 13 customer locations in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 270 MW. As of August 2022, the Company has one customer in North Carolina receiving service under an economic development rate. The total load associated with this rate is approximately 2 MW.

This concrete arch railroad bridge spanning the James River; Richmond, VA

Appendix

Cardinal; state bird of Virginia

The appendices listed below have been updated for the 2022 Update. Note that Appendices 4A through 4G are not able to be provided with the 2022 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class. Accordingly, consistent with the 2020 Plan and the 2021 Update, the Company is providing Appendices 4A through 4G using the 2022 Company Load Forecast. Unless otherwise noted, the appendix includes results for Alternative Plan B.

Appendix 2A	Capacity, Energy, and RECs for Alternative Plans A, B, C, D, and E
Appendix 2B	Capacity Information Directed by the SCC
Appendix 3A	Generation Under Construction
Appendix 3B	Planned Generation Under Development
Appendix 3D	List of Planned Transmission Projects During the Planning Period
Appendix 4A	Total Sales by Customer Class
Appendix 4B	Virginia Sales by Customer Class
Appendix 4C	North Carolina Sales by Customer Class
Appendix 4D	Total Customer Count
Appendix 4E	Virginia Customer Count
Appendix 4F	North Carolina Customer Count
Appendix 4G	Zonal Summer and Winter Peak Demand
Appendix 4H	Projected Summer and Winter Peak Load and Energy Forecast
Appendix 4I	Required Reserve Margin
Appendix 4J	Summer and Winter Peaks
Appendix 4K	Wholesale Power Contracts
Appendix 4O	Commodity Price Forecasts
Appendix 5A	Existing Generation Units in Service
Appendix 5B	Other Generation Units
Appendix 5J	Potential Unit Retirements
Appendix 5T	Winter Capacity for Alternative Plans A, B, C, D, and E
Appendix 6A	Description of Active DSM Programs
Appendix 6F	Description of Approved Phase X DSM Programs
Appendix 7A	List of Transmission Lines under Construction

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