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Commonwealth of Virginia, ex rel. State Corporation Commission,
In re: Virginia Electric and Power Company's 2021 Update to its Integrated Resource Plan pursuant to Va. Code 56-597 et seq.
Case No. PUR-2021-00201

Dear Mr. Logan:

Please find enclosed for filing in the above-captioned proceeding, an electronic copy of the 2021 update (the "2021 Update") to the 2020 Integrated Resource Plan of Virginia Electric and Power Company filed pursuant to § 56-597 *et seq.* of the Code of Virginia and the Commission's Integrated Resource Planning Guidelines established in Case No. PUE-2008-00099 ("Guidelines"). A reference index identifying the sections of the 2021 Update that comply with the Guidelines and with prior Commission orders is also enclosed.

Along with the 2021 Update, the Company is filing one addendum under separate cover. Virginia Addendum 1 contains the consolidated bill analysis directed by the Commission, and is being filed in public and extraordinarily sensitive versions. Accordingly, a Motion for Entry of a Protective Order or Ruling and Additional Protective Treatment is also being filed under separate cover in this proceeding.

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

Very truly yours,

/s/ Vishwa B. Link

Vishwa B. Link

Enclosures

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2021 Update - Reference Index

Order / Guideline	2021 Update Section	Requirement
Guideline (E)	Discussion of Significant Developments, pages 6 to 12	Additionally, by September 1 of each year in which a plan is not required, each utility shall file a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified. If the utility provides a total system IRP in another jurisdiction by September 1 of the year in which a plan is not required, filing the total system IRP from the other jurisdiction will suffice for purposes of this section.
Guideline (E)	Short-Term Action Plan, pages 24 to 25	Each filing shall include a five-year action plan that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP.
Guideline (E)	Motion for Protective Order	If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures.
Case No. PUE-2020-00035 Final Order at 7, n.25	Sensitivity Analyses, pages 22 to 23	In future IRPs and updates, the Company shall, at a minimum, include the following sensitivities: (i) high and low PJM energy prices; (ii) high and low PJM capacity prices; (iii) high and low REC prices; (iv) high and low construction costs; (v) high and low fuel prices; (vi) high and low load forecast scenarios; and (vii) the impact of not meeting legislatively mandated energy efficiency savings targets.
Case No. PUE-2020-00035 Final Order at 9	Transmission System Reliability Analysis, pages 18 to 19	The Commission directs the Company to include in future IRPs and updates the up-to-date reliability analyses of the impacts of retiring traditional fossil generation and adding growing amounts of renewable energy resources on the Company's electric system.
Case No. PUE-2020-00035 Final Order at 9	Alternative Plans, pages 14 to 18	In the future, the Company should also include one or more plans without [a 970 MW CT] "placeholder" additions to address reliability concerns for comparison purposes and to improve transparency in the Company's planning processes
Case No. PUE-2020-00035 Final Order at 10	Existing Supply-Side Generation, pages 37 to 38	We agree that it is appropriate to model retirements as part of the PLEXOS modeling; however, we will also require the Company, for the time being, to continue to file a separate retirement analysis comparable to the economic analysis performed in this case
Case No. PUE-2020-00035 Final Order at 11, n.50	Appendix 2B, Capacity Information Directed by the SCC	Staff recommended and the Company did not object to providing certain capacity-related information in future IRPs and updates, and we so direct as agreed by Staff and the Company. Includes: (i) the most recent PJM Dominion Zone coincident peak forecast; (ii) the most recent PJM Dominion Zone non-coincident peak forecast; (iii) versions of both aforementioned forecasts scaled down to the Dominion load serving entity level; (iv) each Company-owned generation unit interconnected at the transmission-level in the PJM Dominion Zone and the associated nameplate capacity; (v) all Company-owned units that have cleared the PJM capacity market or have capacity performance obligations; (vi) any notification to PJM of the Company's intention to retire or deactivate Company-owned units.
Case No. PUE-2020-00035 Final Order at 11-12 and n.53	Seasonal Capacity and Energy Needs, pages 44 to 49	In future IRPs and updates, the Company should study and report separately on its summer and winter capacity and energy needs, and its alternative plans' ability to meet those requirements. The Company should also give due consideration to market purchases during the winter from the PJM wholesale market, which remains a summer peaking entity; this consideration should include market purchases from merchant generators located within the Dominion Zone that are not subject to a transmission import capacity constraint.
Case No. PUE-2020-00035 Final Order at 12	Energy Efficiency Adjustment, pages 30 to 31	We direct the Company to continue to model energy efficiency targets after 2025
Case No. PUE-2020-00035 Final Order at 14 and n.56	Alternative Plans, pages 14 to 18; Least-Cost Plan Assumptions, page 36	Dominion proposes that future IRPs and updates include a least cost VCEA plan that would meet (i) applicable carbon regulations and (ii) the mandatory RPS Program requirements of the VCEA. For this plan, the Company proposes not to force the model to select any specific resource nor exclude any reasonable resource and allow the model to optimize the accompanying resource plan. Based on the record in this proceeding, we find this proposal to be reasonable at this time. While the Commission recognizes that certain build constraints may be necessary under certain circumstances, the reasonableness of any such build constraints will be subject to Commission review in future proceedings.

2021 Update - Reference Index

Order / Guideline	2021 Update Section	Requirement
Case No. PUE-2020-00035 Final Order at 14-15	Environmental Justice, page 49	The Commission finds that the Company should address environmental justice in future IRPs and updates, as appropriate. As one example, the Company may consider the impact of unit retirement decisions on environmental justice communities or fenceline communities.
Case No. PUE-2020-00035 Final Order at 15-16	Consolidated Bill Analysis, pages 20 to 21; Va. Addendum 1	The Commission will require Dominion to file an updated bill analysis by plan in future IRPs and updates with the following modifications: • The Company shall provide bill impacts over the next ten years for the least cost VCEA plan, the Company's preferred plan, and any additional plans presented, including residential, small general service and large general service customer bills. Each update shall include an additional year of projections beyond 2030 as each year passes and should consistently be compared back to the actual bill as of May 1, 2020. • As proposed by Staff, the Company shall use class allocation factors and projected sales recently used to set rate adjustment clause rates in the bill analysis. • In addition to projections, the analysis shall include actual bill impact information as each year passes. For example, in the 2021 update filing, the Company would include the actual bill information as of December 31, 2020 in the bill analysis.
Case No. PUE-2020-00035 Final Order at 8	PLEXOS Modeling Refinements, page 10	We also direct Dominion to provide an update on the status of its efforts to reconfigure its modeling in its IRP update to be filed this year
Case No. PUE-2016-00049 Final Order at 3 Case No. PUE-2015-00035 Final Order at 18	Reference Index	Dominion shall continue to comply with all requirements directed in prior IRP orders, including the requirement to include an index that identifies the specific location(s) within the IRP that complies with each such requirement.
Case No. PUE-2013-00088 Final Order at 5-6	Nuclear Relicensing, page 11	The Company shall also provide status updates on any discussions it engages in with the United States Nuclear Regulatory Commission on a possible extension for the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, in its future IRP and IRP update filings.

Dominion Energy

Actions Speak Louder

Planning and investing for our future.

2021 Update to the 2020 Integrated Resource Plan

Virginia Electric and Power Company

Case No. PUR-2021-00201 and Docket No. E-100, Sub 165

Filed September 1, 2021

Dominion Energy®

Our Company

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Managing our electric rights-of-way to increase habitats for birds, bees, butterflies, and other pollinators.

Dominion Energy

Our Company

Executive Summary

Dominion Energy Corporate Office; 600 Canal Place; Richmond, VA.

Headquartered in Richmond, Virginia, Virginia Electric and Power Company (the "Company") currently serves approximately 2.6 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company is a subsidiary of Dominion Energy, Inc. ("Dominion Energy")—one of the nation's largest producers and transporters of energy, energizing the homes and businesses of more than seven million customers in 16 states with electricity or natural gas.

In 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. A final order on the 2020 Plan from the NCUC has not been issued as of the date of this filing. The Company now files this 2021 update ("2021 Update") to the 2020 Plan with the SCC and the NCUC consistent with all relevant Virginia and North Carolina laws, regulations, and commission orders.

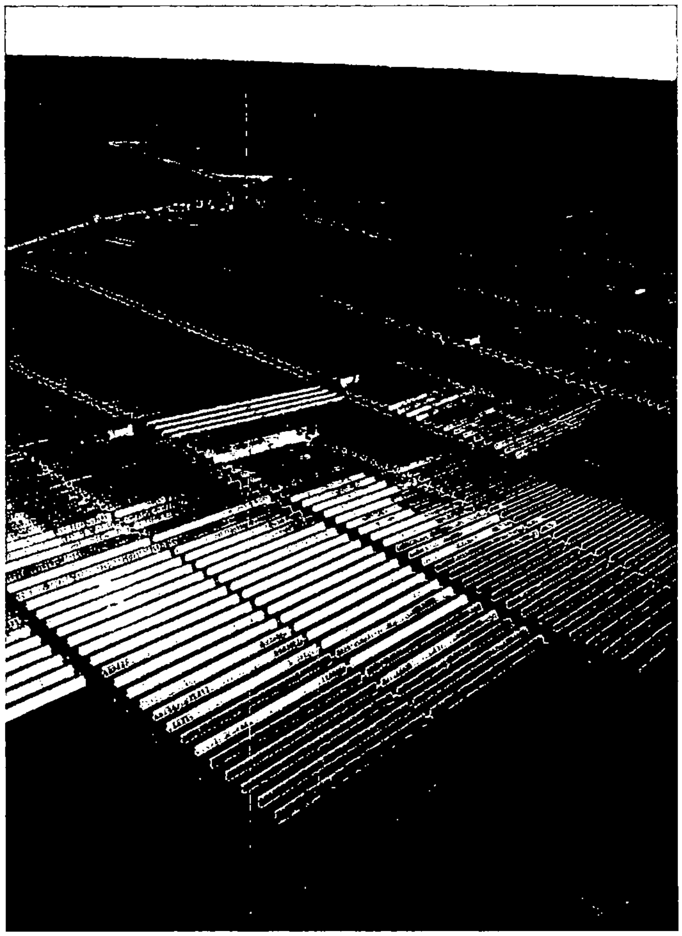
The 2020 Plan explained the Company's commitment to a clean energy future consistent with Dominion Energy's company-wide commitment to achieve net zero carbon dioxide ("CO_2") and methane emissions by 2050; the requirements established in Virginia aimed at a clean energy future through the Virginia Clean 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. Indeed, over the past year or so, the Company has:

- Retired approximately 770 megawatts ("MW") of oil-fired generation (in 2020);
- Placed approximately 250 MW of Company-owned solar in service (in 2020);
- Developed and plans to petition for approval of significant new solar and energy storage resources, including 14 utility-scale projects totaling approximately 746 MW of solar and 70 MW of energy storage and two distributed solar projects totaling approximately 3.6 MW;

- Developed significant new solar and energy storage resources from third-party resources and plans to petition for prudence determinations to enter into up to 25 power purchase agreements ("PPAs") for 33 separate solar and energy storage resources totaling approximately 256 MW of solar and 33 MW of energy storage;
- Received approval from the Nuclear Regulatory Commission ("NRC") for the license extensions for the Company's nuclear units at Surry Power Station, and continued to work to extend the licenses of its nuclear units at North Anna Power Station;
- Completed construction of the 12 MW Coastal Virginia Offshore Wind ("CVOW") demonstration project, and continued the development of the larger build-out of offshore wind generation off the coast of Virginia of up to 180 turbines totaling approximately 2,600 MW;
- Continued to transform the Company's 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; and
- Launched the Smart Charging Infrastructure Pilot Program to provide rebates for electric vehicle ("EV") charging, including public fast charging, multi-family, workplace, and transit, and joined the Electric Highway Coalition to facilitate long-distance electric travel for customers and Company fleet vehicles.

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, including small modular reactors ("SMRs"); and carbon capture and sequestration, all of which have the potential to significantly reduce greenhouse gas emissions.

The 2021 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 2022 and continuing through 2036 (the "Planning Period"), using 2021 as the base year. In certain instances, the Company evaluates the longer 25-year period of 2022 to 2046 (the "Study Period"). Overall, the 2021 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 particular project or action. It is also worth noting that this 2021 Update is a snapshot in time amidst a continuing global pandemic, adding to the usual caveats about the dynamic nature of long-term planning.



Scott Solar Farm; Powhatan, VA.

In this 2021 Update, the Company has updated its long-term planning assumptions, including load forecasts, commodity prices, and projected costs of future resources, and has incorporated a social cost of carbon. Otherwise, the three alternative plans (the "Alternative Plans") presented in this 2021 Update are similar to those shown in the 2020 Plan.

- **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-fired generation to address future system reliability, stability, and energy independence issues.
- **Plan C:** This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation 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, approximately 10 GW of new incremental battery storage would be needed to continue to reliably meet customer load. For context, the Company currently has approximately 100 MW of energy storage under development, in addition to its 16 MW of pilot projects. Over time, as more renewable energy and storage resources are added to the system, the Company will learn if Plan C is capable of maintaining a reliable system.

All Alternative Plans include Virginia's participation in Regional Greenhouse Gas Initiative ("RGGI"), utilize the load forecast prepared by PJM, and assume a capacity factor for all existing and future solar resources of 21.2%, which is the 3-year average of solar tracking facilities in Virginia. The 2021 Update also presents multiple sensitivities on various assumptions. Notably, the Company presents sensitivities on Alternative Plan B using (i) the load forecast it prepared, which the Company believes presents a more reasonable forecast of future growth, and (ii) a projected capacity factor for future solar resources that better reflects their long-term output.

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

Summary Table: 2021 Update Results

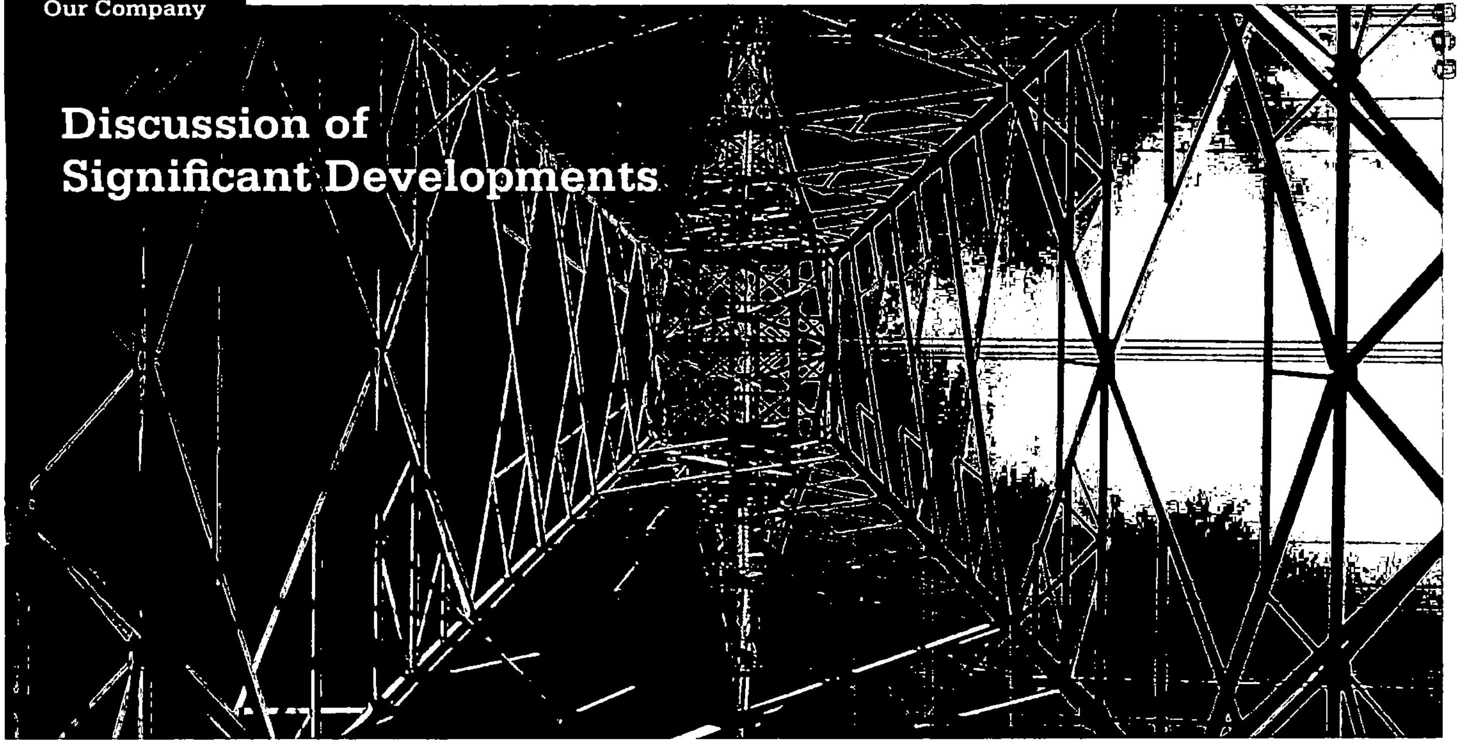
	Plan A	Plan B	Plan C
NPV Total ($B)	$46.0	$67.9	$70.7
Approximate CO_2 Emissions from Company in 2046 (Metric Tons)	18 M	2 M	0
Solar (MW)	820 15 yr. 2,140 25 yr.	14,310 15 yr. 17,790 25 yr.	14,310 15 yr. 20,550 25 yr.
Wind (MW)	– 15 yr. – 25 yr.	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,614 25 yr.
Storage (MW)	– 15 yr. – 25 yr.	2,713 15 yr. 2,713 25 yr.	3,793 15 yr. 12,043 25 yr.
Natural Gas-Fired (MW)	970 15 yr. 970 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. 13,356 25 yr.

As can be seen in the table above, Alternative Plans B and C are very similar over the first 15 years. This general alignment suggests a common pathway for the Company to pursue now while allowing new technologies to mature. While all Alternative Plans in this 2021 Update incorporate only known, proven technologies, the Company fully expects that new technologies could take the place of today's technologies over the Planning 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.

Dominion Energy

Our Company

Discussion of Significant Developments



The Company serves approximately 2.6 million electric customers in Virginia and North Carolina.

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

PJM Load Forecast

PJM incorporated adjustments to its load forecasting methodology into its 2021 PJM Load Forecast that, together with a better understanding of PJM modeling and forecast results, present significant technical and practical challenges and call into question the use of the PJM load forecast in a long-term planning model. These challenges include: (i) disconnect with forecast starting point; (ii) focus on short-term accuracy; (iii) reliance on non-fundamental drivers; (iv) treatment of region-specific nuances; (v) forecast timing; and (vi) forecast translation from DOM Zone to DOM LSE.

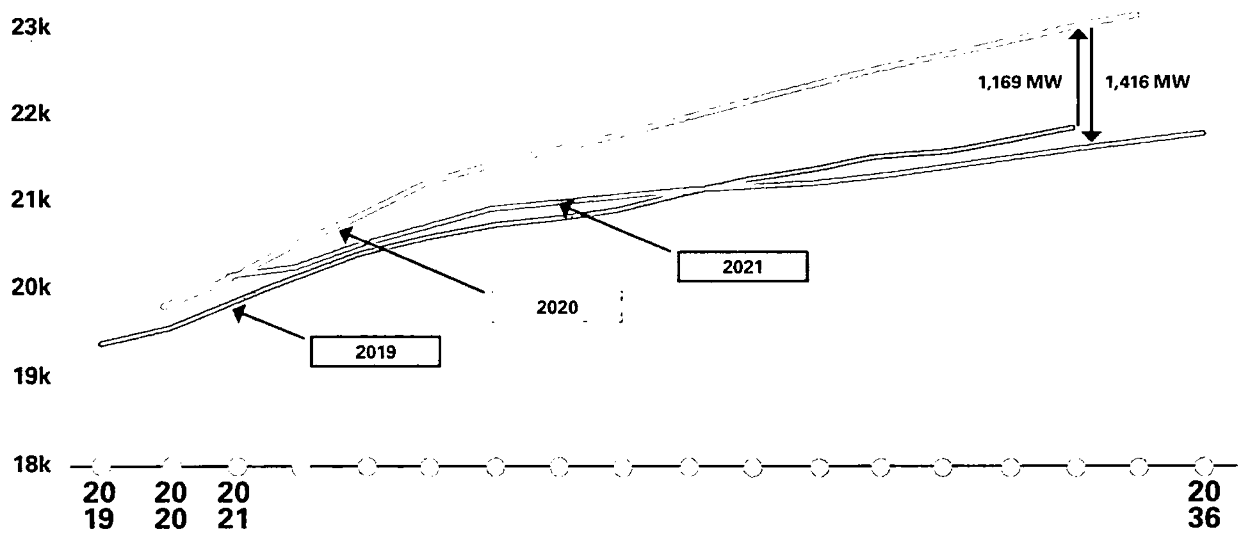
Disconnect with forecast starting point. There is an apparent disconnect in the starting point between actual and forecasted energy in the 2021 PJM Load Forecast. The 2021 PJM Load Forecast starts at 100,235 gigawatt-hours ("GWh"), which is well below both the 105,074 GWh energy on an actual basis and the 105,272 GWh energy on a weather-normal basis for the 12-month period August 2020 to July 2021. As another point of context, on August 12, 2021, DOM Zone reached a new all-time summer peak load of 20,406 MW.[1] The current PJM forecast projects DOM Zone not reaching this level until 2023 for the non-coincident peak and 2027 for the coincident peak. These data points illustrate that PJM's starting point on peak and energy forecast is understated.

Focus on short-term accuracy. PJM's model selection criteria suggest that its forecast is more focused on short-term accuracy. Specifically, PJM model testing has been focused on higher accuracy in the 3-year forecast horizon, which coincides with the PJM capacity market's clearing window, as opposed to the 15- to 25-year window used in the Company's long-term planning process.

[1] The weather on this day was only slightly above 20-year average temperatures at the time of the peak.

As one of the outcomes of the resulting methodology changes, PJM's forecasts have changed materially over the last few years. As shown in the figure, the forecast for 2034 increased by 5.4% and subsequently decreased by 6.2% in the next year. Utilization of a forecast that changes significantly in magnitude and direction from one year to the next presents significant challenges from a long-term planning perspective.

Figure 1.1.1: PJM Forecast, 2019 through 2021



Reliance on non-fundamental drivers. In 2021, PJM introduced a numerical "trend" as an explanatory variable in its model as one of the key forecast methodology changes. This change was based on the model accuracy results of short-term (i.e., one to three years out) historical out-of-sample testing. While the trend variable might have shown more accurate results in the short-term historical testing, use of such a variable represents gaps in model specification that should be directly addressed, especially when the results are to be relied upon for long-term planning. Relying on a continued and growing impact of this trend variable for a 15-year forecast period resulted in a substantially lower forecast that is not supported by underlying fundamentals.

Treatment of region-specific nuances. PJM forecasts for over twenty load zones, maintaining a largely consistent forecasting methodology for each. This approach makes it difficult to appropriately capture modeling nuances specific to different service territories. For example, the 2021 PJM Load Forecast incorporates a data center forecast provided by the Company but does so without isolating the non-data center zonal load. Instead, PJM forecasts non-data center zonal load separately, making the cause and effect of economic variables more difficult to isolate in its forecast models.

Forecast timing. PJM issues its load forecast report once a year in late December or early January.[2] By the time the forecast is utilized in the Company's modeling, the assumptions, which are mostly locked in by September of the prior year, are about nine months old. Significant developments have occurred in the past which makes the forecast obsolete. For example, between the fall of 2020 and the summer of 2021, data center growth occurred faster than projected; and the pandemic impacts on overall loads significantly declined from the initial pandemic periods. Therefore, lack of a full forecast update close to the time of its use renders the forecast outdated and forces its use when the underlying assumptions are no longer valid.

[2] PJM also conducts a forecast update in July; however, it is not comprehensive and very limited forecast information is published.

Forecast translation from DOM Zone to DOM LSE. Deriving a DOM LSE forecast from PJM's DOM Zone forecast presents challenges and limitations that result in unnecessary sources of forecast error. For example, sufficient details are not available to isolate the embedded energy efficiency savings within PJM forecast generally or the DOM LSE component of these savings specifically. Similarly, a behind-the-meter solar load forecast adjustment is made for the entire DOM Zone in PJM's forecast, which cannot be isolated for DOM LSE. Additionally, PJM does not forecast customer class sales, and there is not sufficient data available to derive them from the PJM energy forecast, making customer bill analyses challenging. These sources of forecast error can be avoided by directly forecasting DOM LSE.

Based on these analytical issues, the Company believes that the 2021 PJM Load Forecast presents an understated view of future load growth. Between 2021 and 2026, the 2021 PJM Load Forecast shows the DOM Zone growing from 100,235 GWh to 103,897 GWh, an increase of 3,662 GWh. By contrast, the Company projects that data center demand served by the Company alone will increase by approximately 8,200 GWh in the same period.[3] This implies that PJM forecasts non-data center load in the DOM Zone will decrease by more than 4,500 GWh between 2021 and 2026, an outcome which is not supported by fundamentals. Because growth in DOM Zone load also includes substantial data center load growth in Northern Virginia Electric Cooperative service territory, this implied decrease in DOM Zone load would be even higher if all data center growth in DOM Zone is included. The Company has shared these modeling concerns with PJM, and will continue to collaborate with PJM to improve long-term forecast accuracy.

The Company felt it necessary to include a sensitivity as what it believes to be a more accurate representation of future load growth in its service territory. Accordingly, while the Company has utilized the 2021 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, which is not impaired by the methodological challenges discussed above.

Social Cost of Carbon

The VCEA added a requirement to include the social cost of carbon as a benefit or a cost, whichever is appropriate, in any application to construct new generating facilities. 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. While social cost of carbon estimates in dollars per ton can vary significantly between organizations, the federal government has produced and updated a forecasted social cost of carbon since the 1980s. In February 2021, the Biden Administration published a revised social cost of carbon forecast that begins at $51 per metric ton in 2021.[4]

In this 2021 Update, the Company includes the social cost of carbon as an indirect cost of carbon emissions. This indirect cost was included in addition to the direct cost of carbon generated by the market under applicable carbon regulations. The green line in Figure 1.2.1 depicts the dispatch carbon price included in PLEXOS, a utility modeling and resource optimization tool.

Brunswick Power Station.

[3] PJM's 2021 Load Forecast utilized DOM Zone data center forecast provided by the Company and Northern Virginia Electric Cooperative for their respective service areas. This forecast was provided for the period 2020 through 2025 and was prepared in the fall of 2020.

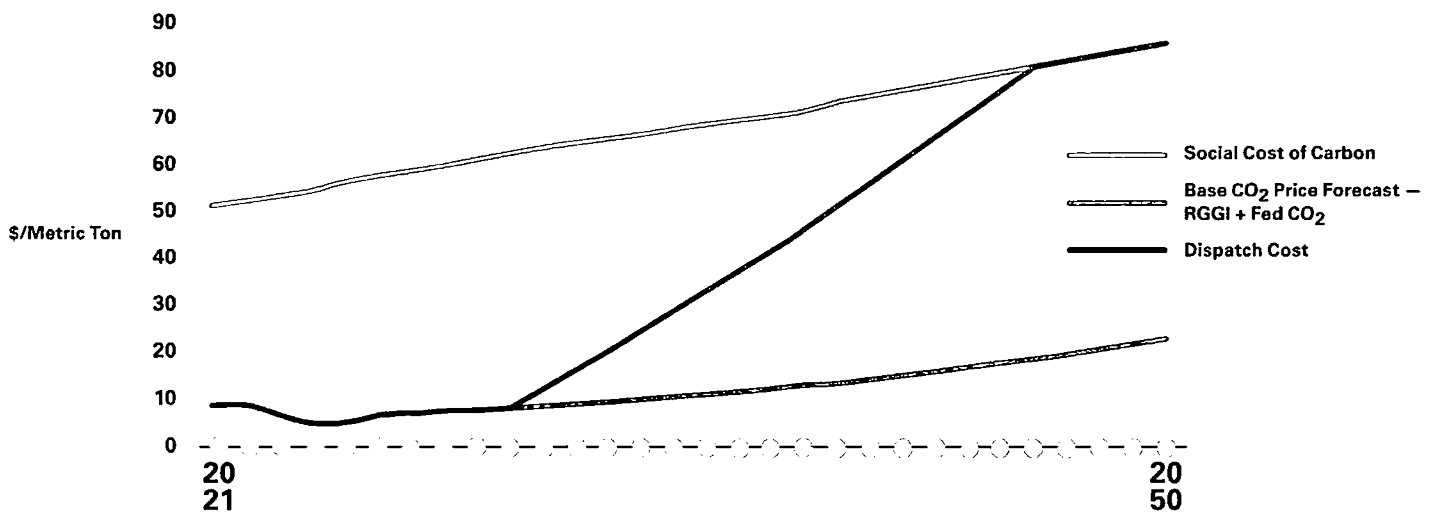
[4] See Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates Under Executive Order 13990 (Feb. 2021), available at https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

As shown in Figure 1.2.1, for the first ten years of the Study Period, the Company included a carbon dispatch adder equal to the forecasted price of a direct carbon tax. Starting in 2031, the Company then blended the forecasted social cost of carbon with the direct carbon tax through 2046 (i.e., the end of the Study Period). 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.

The Company employed this blended approach for two primary reasons in this initial analysis. First, PJM market rules do not currently allow members to factor the social cost of carbon into their cost offers. The Company assumes that the PJM market rules may evolve within the next ten years, as PJM resolves stakeholder concerns over carbon emission leakage between jurisdictions and recognizes societal costs not currently included in offers. Second, the intervening 10-year period provides time for renewable energy facilities to be built to replace the fossil generation component of the Company's current resource portfolio.

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 stay available to ensure system reliability. Because the social cost of carbon is an indirect cost, these costs were not included in the net present value ("NPV") of the Alternative Plans; only costs related to the direct carbon tax were included in the NPV results.

Figure 1.2.1: Carbon Dispatch Price



This 2021 Update presents the Company's initial analysis incorporating the social cost of carbon into its long-term planning process. This analysis will continue to evolve over time. For example, the 2021 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.

Commodity Price and Cost Assumptions

This 2021 Update incorporates updated commodity price forecasts and costs assumptions. The updated commodity price forecasts include the regional impacts of the VCEA along with other market developments identified by ICF Resources, LLC ("ICF"), such as Pennsylvania's participation in RGGI, effective in 2023.

This 2021 Update also incorporates updated build costs for new resources. Notably, build costs for battery storage decreased from the 2020 Plan and continue to decline throughout the Study Period based on short term expectations and National Renewable Energy Laboratory ("NREL") projections (conservative/high scenarios used) for utility scale lithium-ion 4-hour duration battery storage projects as referenced in the 2020 NREL Annual Technology Baseline. Solar build costs increased in the 2021 Update due to recent market trends.

PLEXOS Modeling Refinements

The Company primarily used PLEXOS to develop this 2021 Update. Since the 2020 Plan, the Company has included several refinements in PLEXOS to incorporate the many requirements of the VCEA. These refinements include:

- A dynamic RPS Program requirement based on forecasted customer sales;
- The ability to purchase renewable energy certificates ("RECs") from eligible market sources to satisfy a portion of the Company's RPS Program requirements;
- Deficiency payment logic that allows the model to choose a deficiency payment for RPS Program compliance, as established by the VCEA, if economically advantageous for customers compared to other options;
- Adjustments for excess RECs that can be sold to reduce customer cost; and
- Optimized generating unit retirement logic for least-cost modeling.

The Company will continue to refine its modeling as additional functionality becomes available in PLEXOS. For example, REC banking is not currently available in PLEXOS, but the Company will continue to pursue such improvements for future Plans.

Fixed Resource Requirement Alternative

As described in the 2020 Plan, the Company participates in the PJM capacity planning process to ensure adequate supply of capacity resources for its customer load. As a member of PJM, the Company has the option to secure capacity in order to satisfy mandated reliability requirements through either (i) the reliability pricing model ("RPM") forward capacity market or (ii) the fixed resource requirement ("FRR") alternative.

The Company has participated in the RPM forward capacity market since 2007, and has satisfied its capacity obligation through the RPM auction through May 31, 2022. In April 2021, the Company elected the FRR alternative, with a five-year commitment beginning June 1, 2022, based on its analysis that FRR would provide customer benefits. In the future, the Company could continue to elect the FRR alternative on a year-by-year basis or revert to the RPM forward capacity market with a five-year commitment. The Company will continue to evaluate its options to meet its capacity obligations (i.e., FRR and RPM) to ensure the best result for its customers.

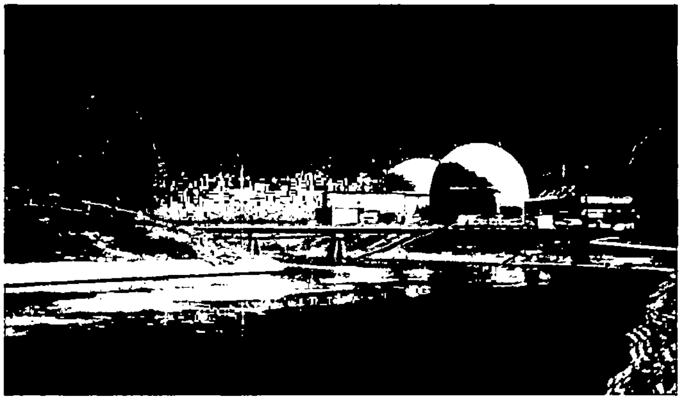
For purposes of long-term planning, the Company continues to model the PJM installed reserve margin requirement, which is not affected by the Company's election of the FRR alternative.

Nuclear Relicensing

An application for a subsequent or second license renewal ("SLR") is allowed during a nuclear unit's first period of extended operation—that is, in the 40 to 60 years range of its service life. A successful SLR application allows nuclear units to operate for an additional 20-year period.

As with other nuclear units, those at the Company's Surry Power Station were originally licensed to operate for 40 years and then were renewed for an additional 20 years. Surry Units 1 and 2 became eligible for SLR in 2012 and 2013, respectively. In November 2015, the Company notified the NRC of its intent to file for SLR for those two nuclear units in accordance with Title 10 of the Code of Federal Regulations Part 54. The licenses for Units 1 and 2 were subsequently renewed on May 4, 2021, permitting continued operation through 2052 and 2053, respectively. Approval by the SCC will also be required for extending the licenses for Surry Units 1 and 2; therefore, the Company's current capacity and energy positions (e.g., as shown in Figures 2.1.1 and 2.1.2) do not include the SLR for these units in its existing generation.

At the Company's North Anna Power Station, Units 1 and 2 became eligible for SLR in 2018 and 2020, respectively. The North Anna SLR application was submitted to the NRC on August 24, 2020. In October 2020, the application was accepted for review by the NRC. This is an important milestone in that the application met the NRC requirements to move forward with both the technical and environmental review processes, which are now underway. The issuance of the renewed license is expected by May 2022, which is 18 months from the date when the application was accepted for review. This will preserve the option to continue operation of North Anna Units 1 and 2 until 2058 and 2060, respectively.



Surry Power Station; Surry County, VA.

Increasing Electrification

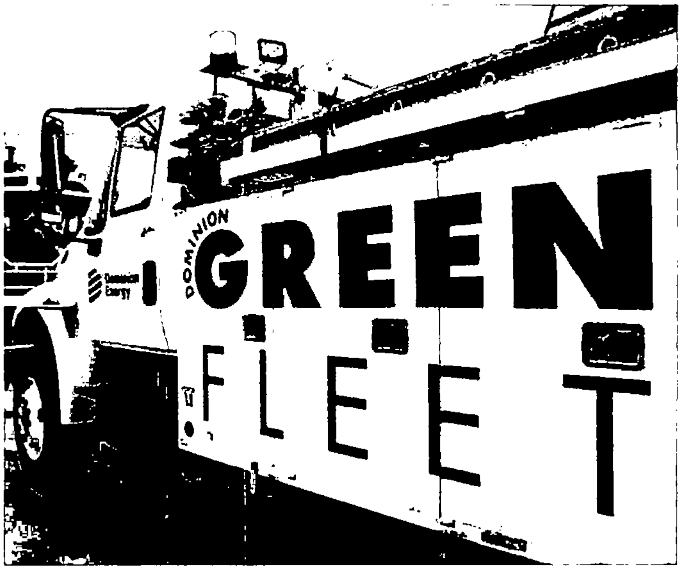
The electrification of transportation is accelerating in Virginia, North Carolina, the United States, and globally.

At the federal level, on August 5, 2021, President Biden signed an executive order to make half of all vehicles sold in 2030 zero-emission vehicles, which includes battery electric, plug-in hybrid electric, and fuel cell EVs. That executive order also initiates development of long-term fuel efficiency and emissions standards to save customers money, reduce pollution, boost public health, advance environmental justice, and address the climate crisis. Automobile manufacturers are making the shift to EVs as well. For example, Ford recently pledged that 40% of its vehicles sold by 2030 will be electric.

At the state level, the Virginia General Assembly passed multiple pieces of legislation earlier this year that provide additional support for transportation electrification. For instance, House Bill ("HB") 1965 requires manufacturers to offer EVs for sale in Virginia, making EVs more available to Virginians. HB 1979 creates a rebate program for the purchase or lease of new and used EVs. The General Assembly also passed HB 2282 earlier this year, which sets a policy to promoting private-sector competition and investment in transportation electrification, in tandem with enabling public utility programs to complement private-sector investments where most effective.

Discussion of Significant Developments

Dominion Energy supports transportation electrification, including the goal of net zero emissions in the transportation sector, which is the largest contributor of greenhouse gas emissions in the United States. On August 10, 2021, Dominion Energy announced a company-wide plan to convert a significant portion of its transportation fleet of 8,600 vehicles to electric power or a clean-burning alternative by 2030. Specifically, 75% of Dominion Energy passenger vehicles, including sedans and sport utility vehicles, will be converted to electric power by 2030. Half of all Dominion Energy work vehicles, from full-size pickup trucks, bucket trucks, to forklifts and all-terrain vehicles will be converted to plug-ins, battery EVs, or vehicles powered by clean-burning fuels such as hydrogen, renewable natural gas and compressed natural gas by 2030. After 2030, all new vehicles, including sedans and heavy-duty vehicles, that are purchased will be either electric or powered by alternative fuels.



Dominion Energy's green fleet includes electric, natural gas, and biodiesel vehicles that are helping it to lower carbon emissions.

This 2021 Update includes an EV load forecast. However, the electrification of transportation now stretches beyond passenger vehicles, to include medium and heavy-duty vehicles, airplane drones, boats and personal watercraft, all-terrain vehicles, trains, forklifts, and farm equipment. The Company is closely monitoring these developments and is actively evaluating opportunities to pilot some of these EVs internally. As an example, the Company has piloted electric forklifts, electric outboard motors, electric lawn mowers, and an all-terrain vehicle, and has a groundbreaking electric school bus program. Dominion Energy is also actively monitoring current and future external business opportunities associated with the electrification of transportation. There is also movement toward electrification of farming and food production in the agriculture sector.

As additional sectors of society work to decarbonize through electrification, the Company expects to grow its system to accommodate their needs.

Autonomous Electric Shuttle; Fairfax County, VA.

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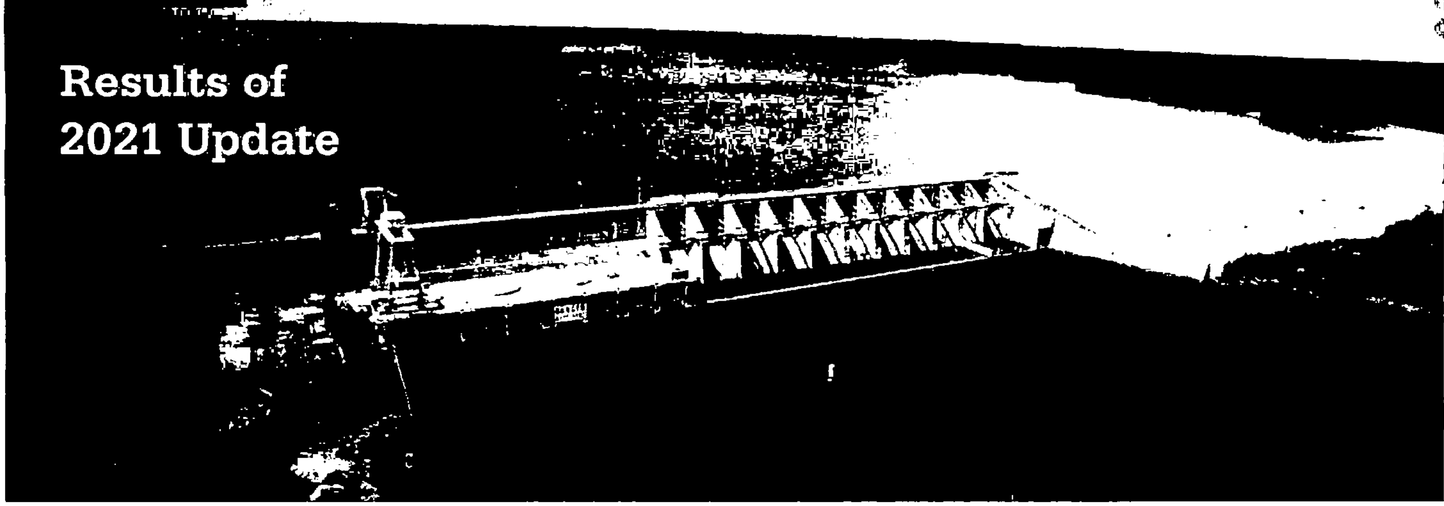


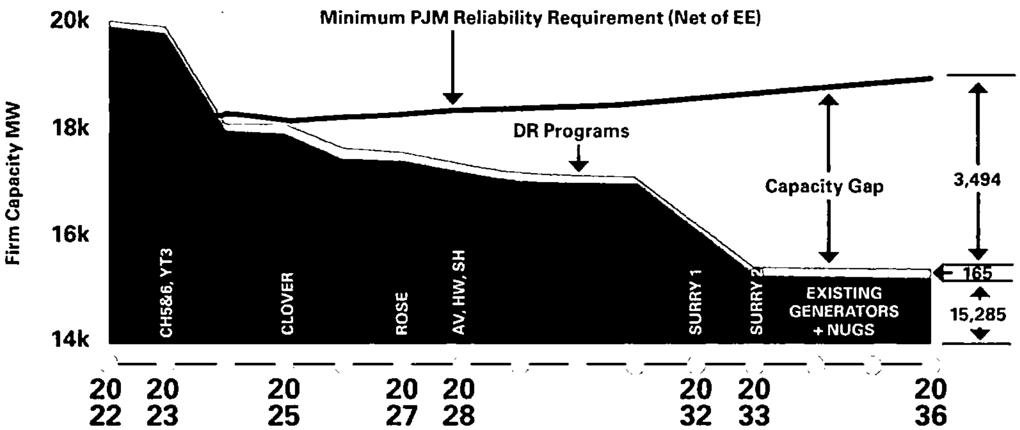
Gaston Hydro Station; Thelma, NC.

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. As always, the Company's options for meeting these future needs are: (i) supply-side resources, (ii) demand-side resources, and (iii) market purchases. A balanced approach—which includes the consideration of options for maintaining and enhancing electric rate stability, increasing energy independence, promoting economic development, incorporating input from stakeholders, and minimizing adverse environmental impact—will help the Company meet growing demand and achieve its clean energy goals while protecting customers from a variety of potential challenges.

Capacity and Energy Positions

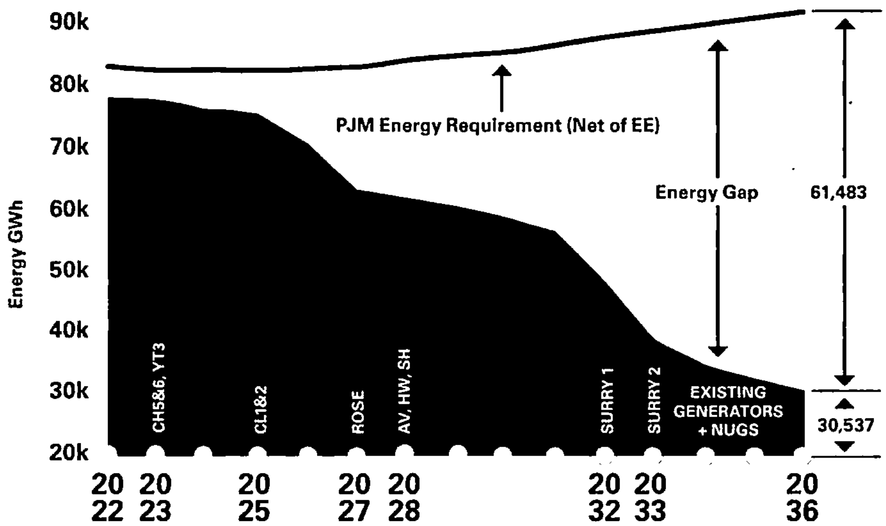
Figures 2.1.1 and 2.1.2 represent the Company's current capacity and energy positions using unit retirement assumptions in Alternative Plan B.

Figure 2.1.1: Current Company Capacity Position (2022 to 2036)



Notes: "Existing Generators + NUGS" also include generation under construction; "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).

Figure 2.1.2: Current Company Energy Position (2022 to 2036)



Notes: "Existing Generators + NUGS" also include generation under construction; "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; "SH" = Southampton (biomass).

Alternative Plans

The 2021 Update presents alternatives representing paths forward for the Company to meet the future capacity and energy needs of its customers, consistent with the 2020 Plan. Notably, more planning work is ongoing and necessary to test the grid under different conditions to ensure system reliability and security in the long term.

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

Plan A: This Alternative Plan presents a least-cost plan that estimates future generation expansion while meeting applicable carbon regulations and the mandatory RPS Program requirements of the VCEA. Plan A is presented in compliance with SCC and NCUC orders and for cost comparison purposes only. For this Alternative Plan, the Company did not force the model to select any specific resource or exclude any reasonable resource and allowed the model to optimize the accompanying resource plan. Notably, 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 preserves natural gas-fired generation to address future system reliability, stability, and energy independence issues.[6] Over the Study Period, this Alternative Plan includes the development of nearly 18 gigawatts ("GW") of solar capacity, approximately 5 GW of offshore wind capacity, and approximately 2.7 GW of new energy storage.

Plan C: 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, approximately 10 GW of new incremental battery storage would be needed to continue to reliably meet customer load. For context, the Company currently has approximately 100 MW of energy storage under development, in addition to its 16 MW of pilot projects. Over time as more renewable

[6] The natural gas resources preserved in Alternative Plan B differs from the 2020 Plan for two primary reasons: (i) Alternative Plan B no longer includes a 970 MW placeholder to address system reliability issues, and (ii) Rosemary is no longer classified as a natural gas unit.

energy and storage resources are added to the system, the Company will learn if Plan C is capable of maintaining a reliable system.

All Alternative Plans include Virginia's participation in RGGI, utilize the load forecast prepared by PJM, and assume a capacity factor for all existing and future solar resources of 21.2%, which is the 3-year average of solar tracking facilities in Virginia, as required. In addition, Alternative Plans B and C incorporate the social cost of carbon, as discussed in ***Social Cost of Carbon.***

Figures 2.2.1 through 2.2.3 show the build plans for each Alternative Plan. 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.

Figure 2.2.1: Alternative Plan A (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2021	20	15							
2022	62	416							
2023		307							CH5&6, YT3, VCHEC, AV, HW, SH
2024								900	
2025								1,000	
2026						485		600	
2027						485		300	
2028								400	
2029								500	
2030								500	
2031								600	
2032							Surry 1	700	
2033							Surry 2	800	
2034								900	
2035								1,000	
2036								1,000	
TOTAL	82	738	-	-	-	970	1,676	9,200	2,567

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

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Figure 2.2.2: Alternative Plan B (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2021	20	15							
2022	62	416	52		20				
2023	746	317	102		83				CH5&6, YT3
2024	468	252	100		90				
2025	663	357	120		120				CL1&2
2026	663	357	120	2,587	120				
2027	663	357	120		150				Rosemary
2028	624	336	100		180				AV, HW, SH
2029	624	336	100		300				
2030	663	357	80		240				
2031	624	336	60		240				
2032	624	336	60		300		Surry 1		
2033	624	336	40	2,587	300		Surry 2		
2034	624	336	20		330				
2035	702	378	20		240				
2036									
TOTAL	8,394	4,822	1,094	5,174	2,713	-	1,676	-	2,561

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

Figure 2.2.3: Alternative Plan C (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2021	20	15							
2022	62	416	52		20				
2023	746	317	102		83				CH5&6, YT3
2024	468	252	100		90				
2025	663	357	120		120				CL1&2
2026	663	357	120	2,587	120				
2027	663	357	120		150				Rosemary
2028	624	336	100		180				AV, HW, SH
2029	624	336	100		300				
2030	663	357	80		240				
2031	624	336	60		240				
2032	624	336	60		510		Surry 1		
2033	624	336	40	2,587	480		Surry 2		
2034	624	336	20		510				
2035	702	378	20		450				
2036					300				
TOTAL	8,394	4,822	1,094	5,174	3,793	-	1,676	-	2,561

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

A difference from the 2020 Plan is that Alternatives Plans B and C no longer 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. Associated reliability analyses are complex, under development, and still ongoing, as discussed in ***Transmission System Reliability Analysis.*** Future Plans will be updated, as needed, based on the results and findings of these reliability analyses.

As seen in Figures 2.2.2 and 2.2.3, Plans B and C are very similar over the first 15 years of the Planning Period. This alignment between Plans B and C suggests a common pathway for the Company to pursue now while allowing new technologies to emerge and mature and allowing analysis and study to continue.

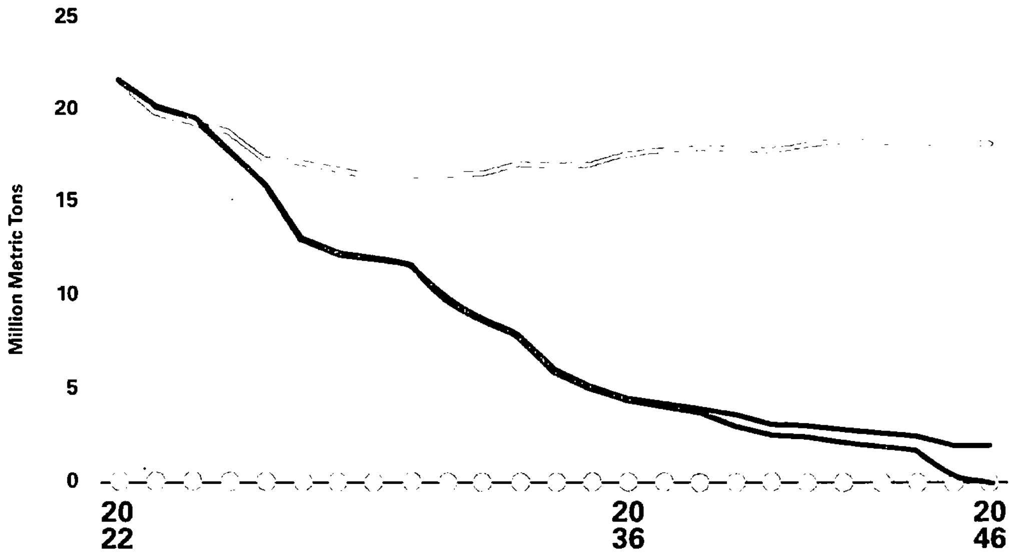
Figure 2.2.4 shows projected CO_2 emissions from the Company's fleet for the duration of the Study Period.

Figure 2.2.4 – System CO_2 Output from Company Fleet for Alternative Plans

Plan A
Plan B
Plan C

System CO_2 Emissions

	2036	2046
Plan A	18	18
Plan B	5	2
Plan C	4	0



Transmission System Reliability Analysis

In the 2020 Plan, the Company provided an initial overview of the reliability analyses that it would need to perform to investigate the probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generator 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 concerns and issues are actively under study and development by the Company, and include the traditional reliability concerns that are also essential to continue to study. These include North American Electric Reliability Corporation ("NERC") Reliability Standard criteria and violations, PJM reliability criteria, existing Company criteria, thermal loading issues, voltage issues, and more. In addition to investigating these newer and traditional reliability issues, the Company is also investigating solutions, which include existing and new technologies, that may be needed to address these reliability issues in the future. Existing technologies include — transmission substations, transmission lines, synchronous generators, transformers, capacitor banks, reactor banks, static 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 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 been developing 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.

Net Present Value Comparison

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

Figure 2.4.1: NPV Results ($B)

	Plan A	Plan B	Plan C
Total System Costs[1]	$32.5	$52.7	$55.4
Grid Transformation Plan (Net of Benefits)	$0.2	$2.0	$2.0
Strategic Underground Program	$1.9	$1.9	$1.9
Transmission Underground Pilots	$0.1	$0.1	$0.1
Transmission	$9.2	$9.2	$9.2
Other Capital	$2.1	$2.1	$2.1
Total Plan NPV[2, 3]	**$46.0**	**$67.9**	**$70.7**
Plan Delta vs. Plan A	**NA**	**$22.0**	**$24.7**

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 2.2.3 plus approved, proposed, future, and generic DSM; costs related to environmental laws and regulations; renewable energy integration costs; and REC purchases and sales.
(2) All NPVs are calculated with a 6.46% discount rate.
(3) Numbers may not add due to rounding.

Consolidated Bill Analysis

The Company completed a consolidated bill analysis for each Alternative Plan presented in the 2021 Update. This analysis encompasses three different customer classes and spans 2021 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 dictate 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 15-year 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 of 21.2%—the 3-year average of solar tracking facilities in Virginia. As discussed in prior proceedings, the Company believes that a projected 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 25.4% capacity factor for solar resources ("Company Methodology").

The electric bill of the Company's typical residential customer in Virginia (i.e., one which 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 2.5% over the next 15 years. When using the Company Methodology and December 31, 2019 as the baseline, the projected increase in the typical residential customer's bill is approximately 2.1% on a compound annual basis.

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

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

	Plan B – Company Methodology[1]			Plan B – Directed Methodology		
	Projected Bill	CAGR Dec 2019	CAGR May 2020	Projected Bill	CAGR Dec 2019	CAGR May 2020
12/31/19	$122.66			$122.66		
05/01/20	$116.18			$116.18		
05/01/21	$117.47			$117.47		
Year End 2030	$163.13	2.6%	3.2%	$177.89	3.4%	4.1%
Year End 2035	$171.05	2.1%	2.5%	$199.35	3.1%	3.5%
Total Bill Increase *(May 2020-2035)*	$54.87			$83.17		

Note: (1) Derived using the system resources selected in Alternative Plan B incorporating the Company Methodology for the purposes of the billing analysis, including forecasted sales growth, forecasted class allocation factors, and a 25.4% capacity factor for solar resources.

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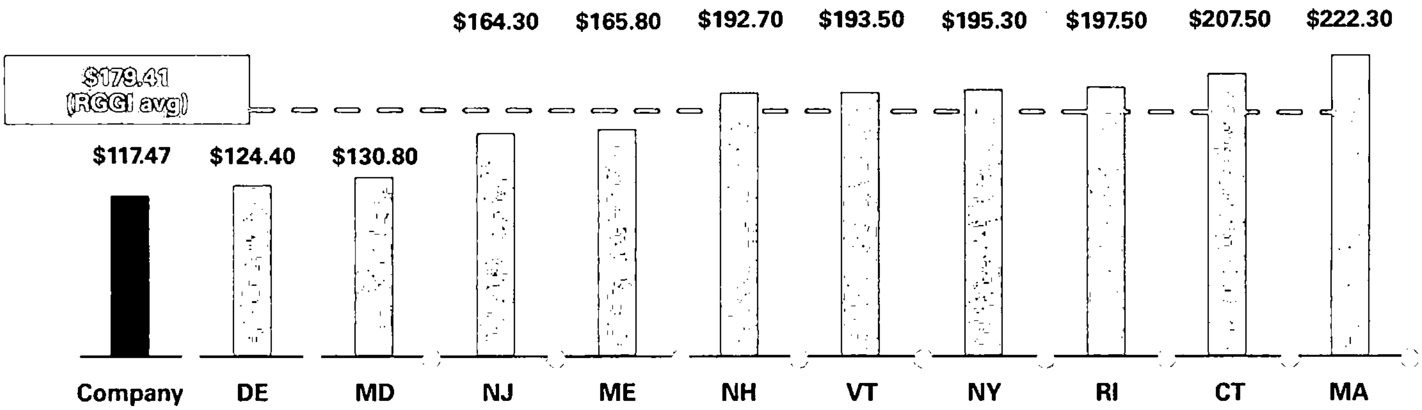
For perspective, the average bill for residential customers in states participating in RGGI, normalized for 1,000 kWh monthly usage, is approximately $179.41 based on federal data. The Company's typical residential bill as of May 1, 2021 (i.e., $117.47) compares favorably to this benchmark, as shown in Figure 2.5.2.

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



Note: (1) Based on residential rate data for RGGI states from U.S. Energy Information Administration as of June 2021, normalized for 1,000 kilowatt-hour monthly usage. Typical 1,000 kilowatt-hour residential bill for Company uses rates in effect May 1, 2021.

Sensitivity Analyses

The Company conducted several sensitivities for this 2021 Update on Alternative Plan B to show the potential paths forward under different future conditions consistent with SCC and NCUC requirements. For some sensitivities, the Company re-optimized the build plan. For others, the Company kept the same build plan as for Plan B but then applied different assumptions.

The Company re-optimized the build plan using different load forecasts. As discussed above, Alternative Plan B utilizes the 2021 PJM Load Forecast. While the Company believes that this load forecast understates the load growth in the Company's service territory as discussed in ***PJM Load Forecast***, the Company increased and decreased the 2021 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 2021 Company Load Forecast. Finally, the Company ran a case reflecting only proposed or approved DSM programs as required by the SCC.

Figure 2.6.1 shows the results of these sensitivities.

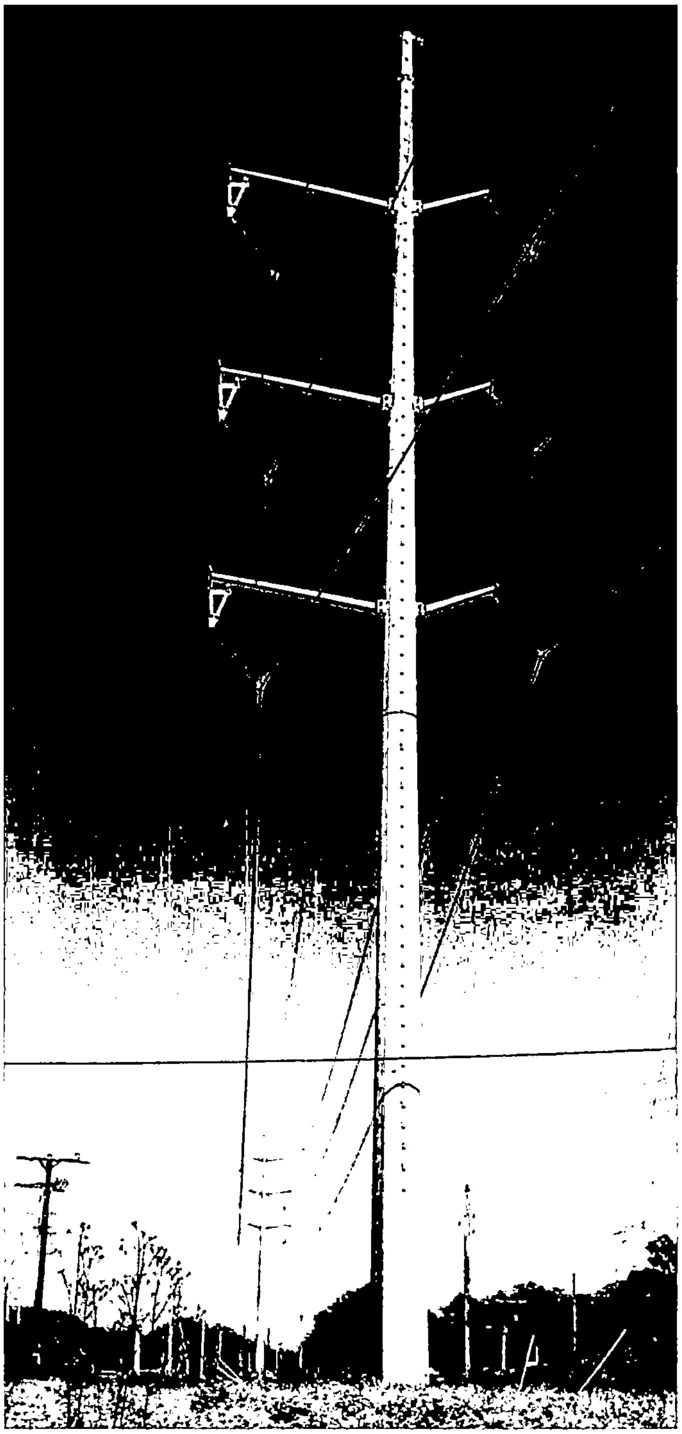
Figure 2.6.1: 2021 Update Sensitivities Table on Load Forecast

	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)	$67.9	$69.8	$66.0	$78.3	$67.1
Approximate CO_2 Emissions from Company in 2046 (Metric Tons)	2 M	2 M	2 M	2 M	2 M
Solar (MW)	14,310 15 yr. 17,790 25 yr.	14,310 15 yr. 18,570 25 yr.	14,310 15 yr. 14,090 25 yr.	14,728 15 yr. 24,508 25 yr.	14,310 15 yr. 18,448 25 yr.
Wind (MW)	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,174 25 yr.
Storage (MW)	2,713 15 yr. 2,773 25 yr.	2,713 15 yr. 2,773 25 yr.	2,713 15 yr. 2,773 25 yr.	2,713 15 yr. 2,773 25 yr.	2,713 15 yr. 2,773 25 yr.
Natural Gas-Fired (MW)	– 15 yr. – 25 yr.	– 15 yr. – 25 yr.	– 15 yr. – 25 yr.	– 15 yr. – 25 yr.	– 15 yr. – 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.

The Company also ran input variations on Alternative Plan B to show the effect on NPV using a range of possible costs. First, the Company 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 RGGI + Federal CO_2 High Fuel Price commodity forecast and the RGGI + Federal CO_2 Low Fuel Price commodity forecast. See ***Commodity Price Assumptions*** for a description of these forecasts and the interrelated nature of these commodity prices. Second, the Company ran a sensitivity that increased and decreased the projected capital construction costs of different resources by 10%. Third, the Company ran a sensitivity that used a projected design solar capacity factor of 25.4% instead of the three-year historical average capacity factor. As discussed in prior proceedings, the Company believes design capacity factor, which represents an average capacity factor over the life of the facility (i.e., not just three years), taking into account degradation, is a better reflection of long-term output for tracking solar facilities. Notably, however, the 3-year average capacity factor for solar units has increased by more than 2% since last year, moving closer to the anticipated design capacity factor of 25.4% for tracking solar facilities. Figure 2.6.2 shows the summarized results.

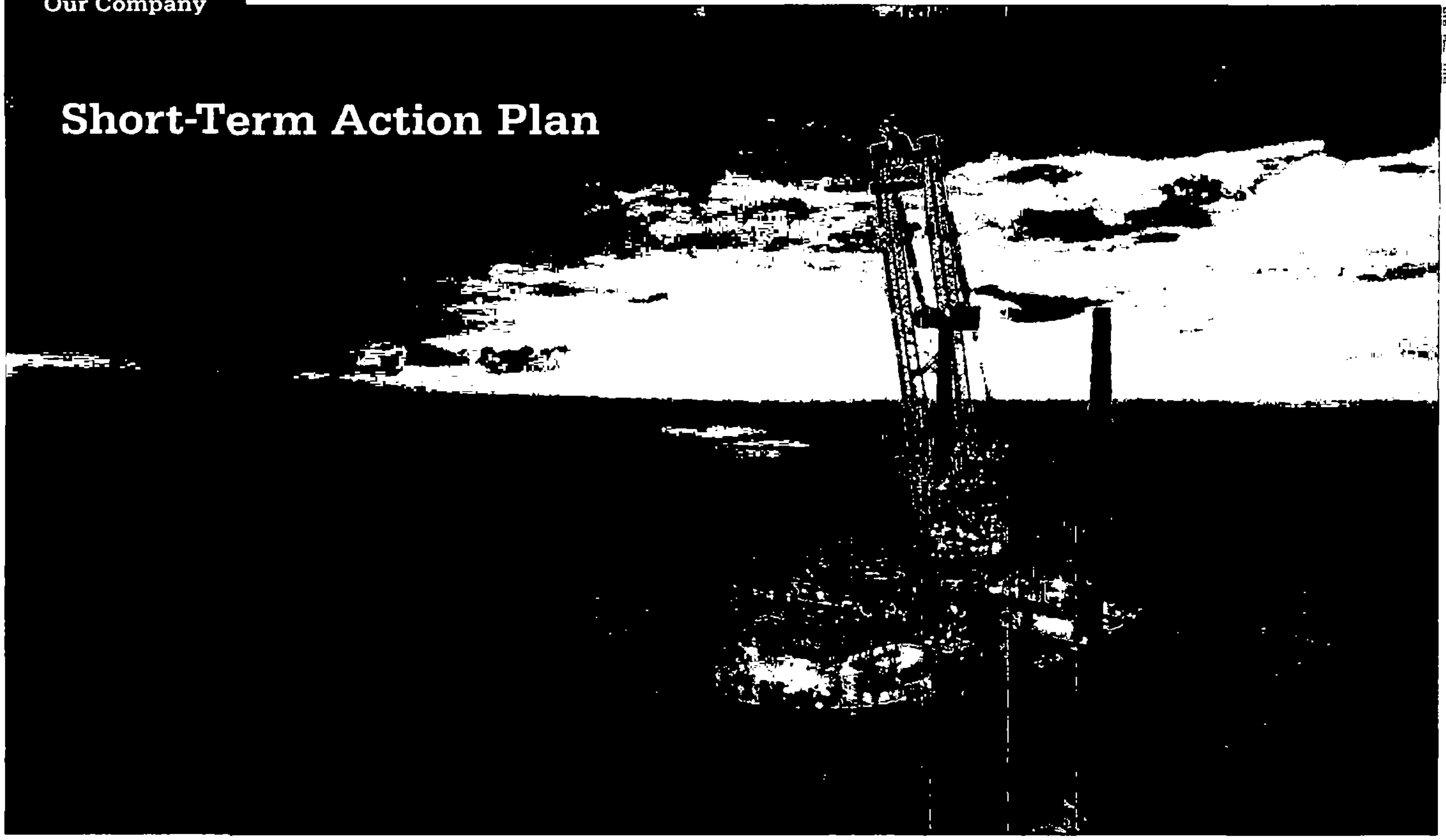
Figure 2.6.2: 2021 Update Sensitivities on NPV Costs

Plan Description	NPV Total (SB)
Plan B	$67.9
Plan B: High Fuel Market Prices	$77.9
Plan B: Low Fuel Market Prices	$66.9
Plan B: High Capital Construction Costs	$70.6
Plan B: Low Capital Construction Costs	$65.2
Plan B: 25.4% Solar Capacity Factor	$67.5



We continue to invest in high-voltage transmission assets to strengthen grid reliability to our electric customers.

Short-Term Action Plan



Dominion Energy's Coastal Virginia Offshore Wind Project.

The short-term action plan provides the Company's strategic plan for the next five years (2021 to 2026). 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 RPS Program requirements established by the VCEA, including related requests for approval of certificates of public convenience and necessity and for prudence determinations related to PPAs;
- Continue development and begin construction of a larger build-out of offshore wind off the coast of Virginia;
- Meet its targets under Virginia's mandatory RPS Program standard 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 submitted for North Anna Units 1 and 2 in August 2020;
- 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

Over the next five years, the Company will continue to identify and propose new or revised DSM programs that meet the existing requirements of the Grid Transformation and Security Act of 2018 ("GTSA") and the requirements and targets in the VCEA in conjunction with the DSM stakeholder process. The Company also expects to complete a new market potential study in late 2021 and is currently working with an external consultant, Cadmus, and stakeholders towards development of a long-term DSM strategy and plan that will be filed with its 2021 DSM proceeding.

In Virginia, the Company filed its Phase IX DSM application in December 2020 seeking approval of 11 DSM programs. The SCC must issue its final order on this application in September 2021.

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 to construct facilities required to meet the needs of its customers. Generally, the Company anticipates transmission projects that are needed to rebuild aging infrastructure, and to interconnect data center customers 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 ***Transmission System Reliability Analysis***.

Distribution

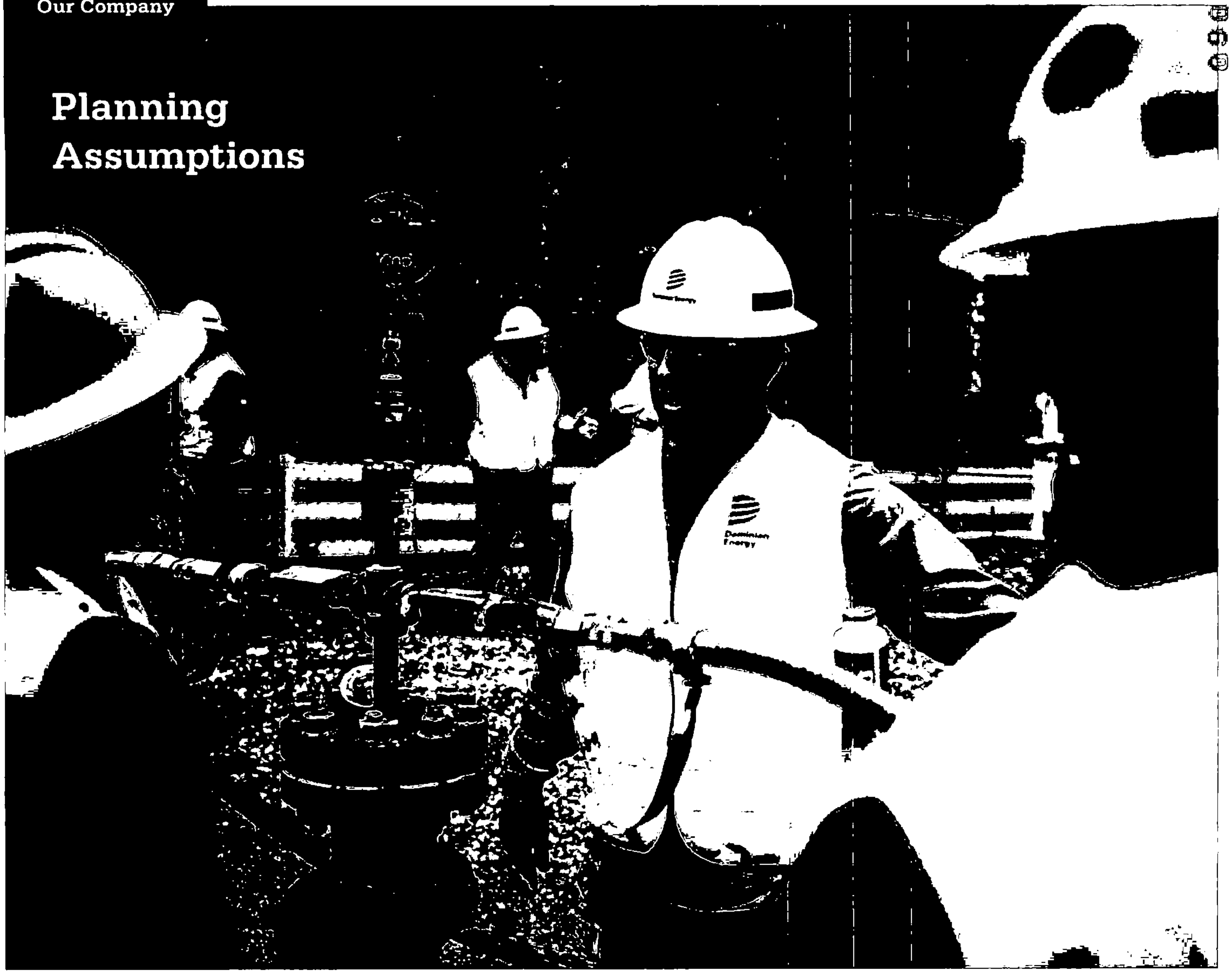
Over the next five years, the Company will continue to assess its distribution system, adapt the distribution grid to meet the needs of a modernized system, and implement solutions and programs to meet the needs of its customers both today and in the future. Specifically, the Company expects to take 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 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 a standardized screening process to consider non-wires alternatives for distribution grid support;
- Continue its Strategic Undergrounding Program ("SUP");
- Pilot vehicle-to-grid ("V2G") technology through the Electric School Bus Program;
- 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

Our Company

Planning Assumptions



Brandon Aycock shares how Zero Emissions Vacuum and Compression (ZEVAC®) technology will be used to capture and recycle natural gas during maintenance and inspection activities in Apex, NC.

The Company's generation planning process for this 2021 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 2021 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.

Load Forecast

The 2021 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 2021 Company Load Forecast and presents a sensitivity using the Company Load Forecast, shown in ***Sensitivity Analyses***.

As with the 2020 Plan, the load forecasts in the 2021 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*** below. The 2021 Update includes an adjustment for voltage optimization as part of the generic energy efficiency adjustment described further in ***Energy Efficiency Adjustment***.

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Figures 4.1.1 and 4.1.2 compare the PJM Load Forecast with the Company Load Forecast for both 2020 and 2021; as can be seen, the 2021 PJM Load Forecast dropped dramatically. As discussed in ***PJM Load Forecast***, the material changes to PJM's Load Forecast and underlying methodology lead the Company to believe that it does not represent a realistic long-term forecast for use in system planning.

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

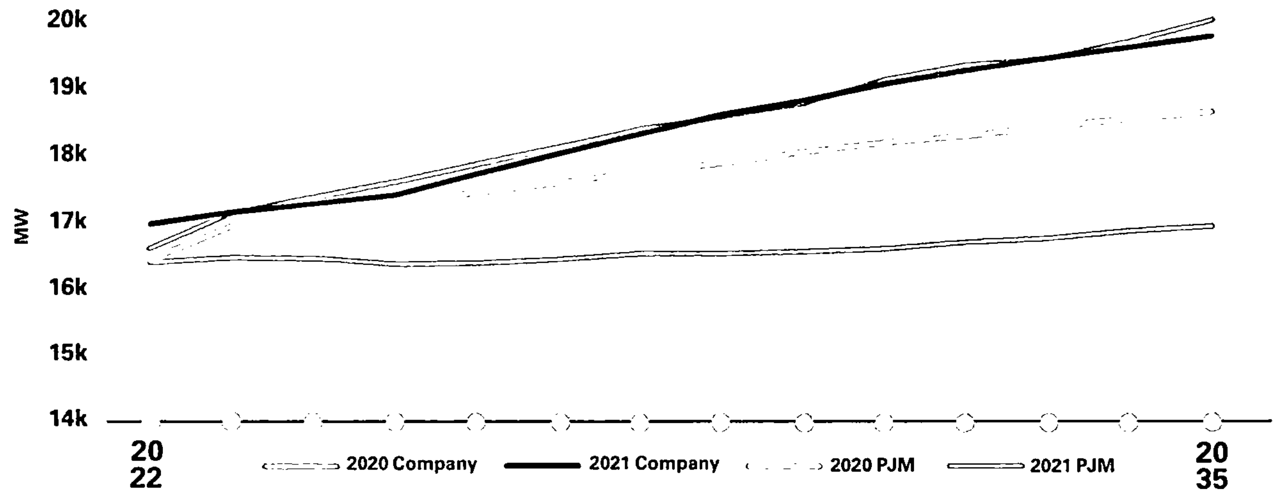
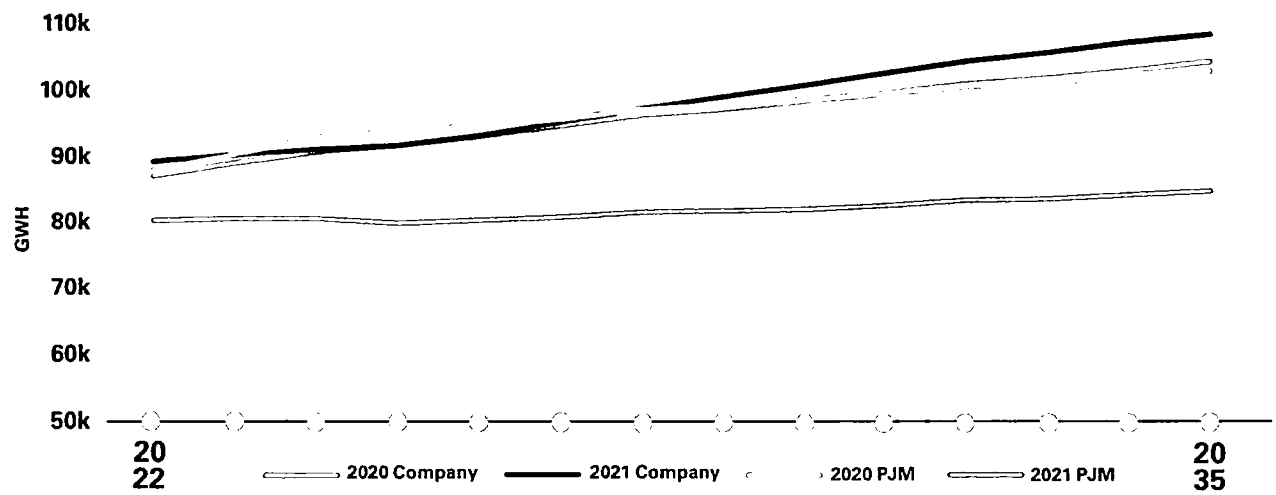


Figure 4.1.2: DOM LSE Annual Energy Comparison



Notably, both the 2021 PJM Load Forecast and the 2021 Company Load Forecast implicitly incorporate the effects on load of the ongoing public health emergency related to the spread of COVID-19 by way of the economic variables such as actual and forecast gross domestic product and employment.

PJM Load Forecast

For the 2021 Update, the Company used the same methodology as in the 2020 Plan to perform a downward adjustment on the 2021 PJM Load Forecast (published in January 2021) for the DOM Zone in order to arrive at the DOM LSE level. Chapter 4.1.1 of the 2020 Plan describes that process. Figure 4.1.1.1 presents the adjusted 2021 PJM Load Forecast. Overall, the PJM Load Forecast anticipates that summer peak demand and energy for the DOM Zone will increase at CAGR of approximately 0.9% and 0.6%, respectively, between 2021 and 2036.

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 2021 Update using a summer peak to align with PJM's DOM Zone summer coincident peak demand and energy forecast.

Springfield Solar Farm; Springfield, VA.

Figure 4.1.1.1: 2021 PJM Load Forecast Adjusted to LSE Requirements

Year	DOM Zone Coincident Peak (MW)	DOM LSE Equivalent (MW)	DOM Zone Energy (GWh)	DOM LSE Equivalent (GWh)
2021	19,540	15,875	100,235	80,026
2022	19,648	15,904	100,894	80,314
2023	19,903	15,983	101,716	80,361
2024	20,109	15,995	102,843	80,427
2025	20,302	15,910	103,369	79,948
2026	20,367	15,940	103,897	80,336
2027	20,449	15,998	104,415	80,734
2028	20,532	16,081	105,191	81,368
2029	20,568	16,086	105,450	81,574
2030	20,607	16,114	105,826	81,888
2031	20,682	16,166	106,456	82,403
2032	20,776	16,258	107,429	83,209
2033	20,883	16,326	107,828	83,533
2034	20,992	16,417	108,489	84,089
2035	21,070	16,487	109,221	84,585
2036	21,129	16,559	110,156	85,087
2037	21,239	16,636	110,851	85,652
2038	21,350	16,735	111,551	86,219
2039	21,462	16,826	112,255	86,775
2040	21,574	16,928	112,964	87,321
2041	21,687	16,991	113,677	87,877
2042	21,800	17,082	114,394	88,453
2043	21,914	17,180	115,116	89,039
2044	22,029	17,297	115,843	89,628
2045	22,144	17,372	116,574	90,222
2046	22,260	17,466	117,310	90,818

Company Load Forecast

The Company made a few changes to its methodology as described in Chapter 4.1.2 of the 2020 Plan.

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 2021 Company Load Forecast. Overall, the Company anticipates the DOM LSE summer peak demand and energy forecast CAGR of 1.2% and 1.4%, respectively.

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

- 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 peak-to-energy ratios from the past ten years after taking out data center load. Derivation of DOM LSE peak using this approach, as opposed to modeling both peak and energy in isolation, promotes consistency and prevents abrupt changes in the resulting load factor from differences in two independent models.
- 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.
- Data center sales, energy, and peak demand are now being forecasted by the Company as a standalone category and are being applied to the Company's sales, peak, and energy forecasts as an exogenous adjustment. This action is consistent with a recommendation provided by Itron Inc., in its review of the Company's load forecasting methodology, as discussed in the 2020 Plan. The forecast utilizes a combination of internal forecasting through 2026 and declining growth rates for 2027 and beyond.

Figure 4.1.2.1: 2021 Company Load Forecast

Year	2021 Company Summer Peak Forecast (NCP) (MW)	2021 Company Energy Forecast (GWh)
2022	16,665	89,368
2023	16,757	90,421
2024	16,809	91,285
2025	16,787	91,783
2026	16,962	93,263
2027	17,233	95,199
2028	17,520	97,199
2029	17,792	99,096
2030	18,050	100,886
2031	18,315	102,662
2032	18,588	104,425
2033	18,797	105,806
2034	19,017	107,174
2035	19,220	108,385
2036	19,429	109,550
2037	19,566	110,277
2038	19,777	111,834
2039	19,989	113,412
2040	20,205	115,013
2041	20,422	116,637
2042	20,642	118,283
2043	20,864	119,952
2044	21,088	121,645
2045	21,315	123,362
2046	21,544	125,104

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- The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load. For this 2021 Update, the Company has revised its EV forecasting process. A separate EV forecast has been developed and added to energy, peak, and sales forecast as a post-model adjustment. The EV forecast was developed by utilizing an EV forecast from ICF, which in turn utilizes the NREL's Electrification Futures Study.

Energy Efficiency Adjustment

As with the 2020 Plan, the load forecasts in this 2021 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 are currently pending approval before the SCC in Case No. PUR-2020-00274. 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 includes only an adjustment for previously-approved and pending programs—the Category 1 Programs. Alternative Plans B and C also include the additional adjustment for generic EE—the Category 2 Program.

To estimate the generic EE, the Company reviewed the actual savings results and costs of its EE programs for 2012 through 2020 in order to develop an average cost per net kWh saved on a persistent savings basis (expressed as "$/kWh"). The Company analyzed the $/kWh as a total portfolio view, excluding low income and as a low-income only view. The total portfolio $/kWh, excluding low income, was calculated to be approximately $0.058/kWh (or $58/MWh), and the low income-only $/kWh was calculated to be approximately $0.253/kWh (or $253/MWh). The Company then applied the portfolio and low income $/kWh in the necessary quantities to meet the legislative directives noted above at the appropriate levels.

This approach 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 on page 31 identify the EE energy and capacity adjustments to the load forecasts used in this 2021 Update, respectively.

Roanoke Rapids.

Figure 4.1.3.1: EE Energy Forecast Adjustment

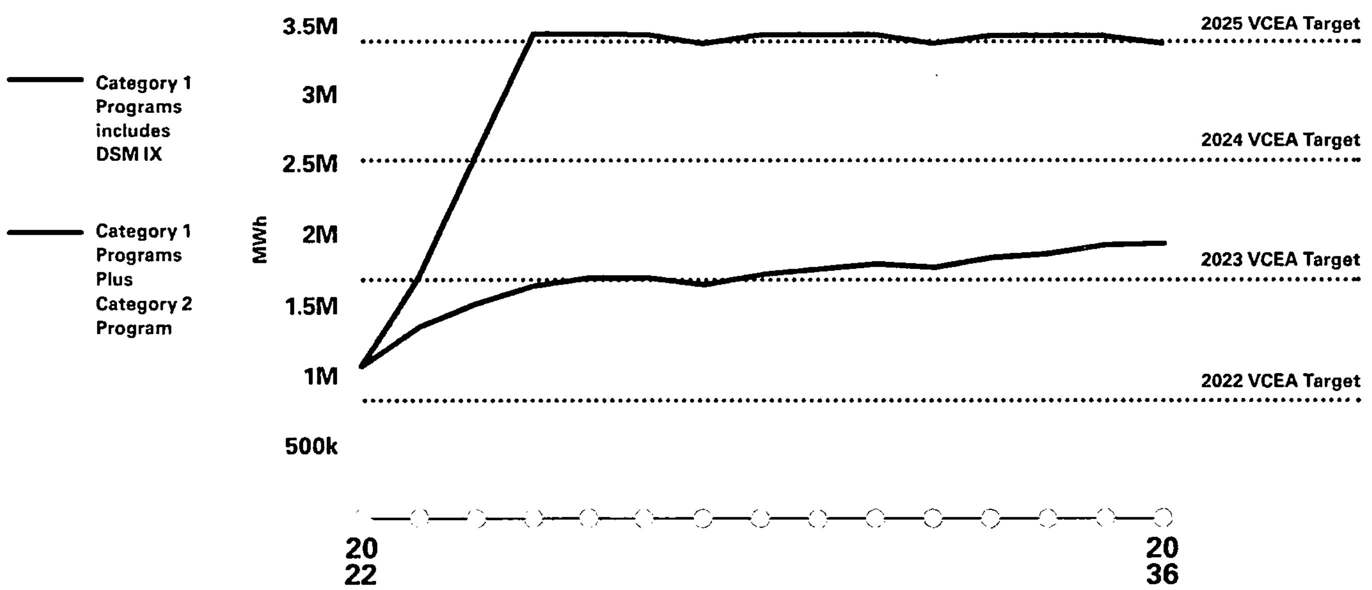
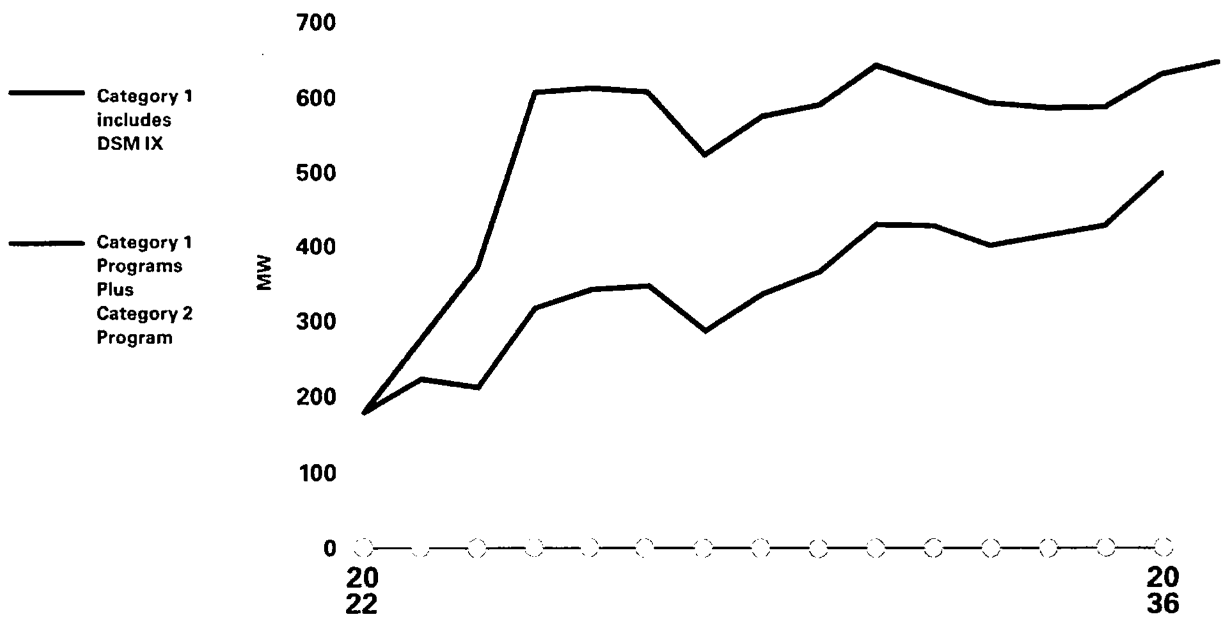


Figure 4.1.3.2: EE Coincident Summer Peak Demand Forecast Adjustment



Retail Choice Adjustment

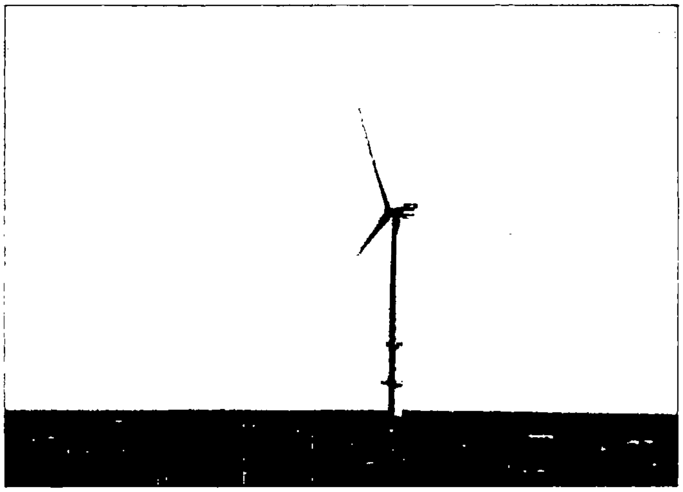
For the 2021 Update, the Company used the same methodology described in Chapter 4.1.1 of the 2020 Plan to adjust the load forecasts for customers in the Company's service territory that have chosen (or may choose) to purchase energy and capacity from third-party electric suppliers under Va. Code § 56-577 ("Choice Customers"). The only additional assumption in the Company's calculation of future Choice Customer reduction in the 2021 Update is that the customers who elected retail choice during the year 2021 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 2021 Update, the Company utilized the preliminary PJM ELCC study published in March 2021 to estimate the capacity value of solar, offshore wind, and storage resources. This approach indicated the capacity value of solar is currently in the 54% range, decreasing over time as solar saturation grows. For offshore wind, the capacity value is currently in the 27% range, and decreases over time as offshore wind saturation grows. For storage, the Company is utilizing a capacity value of 79% for four-hour systems and 93% for eight-hour systems. PJM currently performs its ELCC calculations at the hourly or daily level. PJM published a new study in August 2021 that showed higher capacity values for offshore wind with little change to solar and storage. While this new study could not be incorporated into the 2021 Update, it will be reflected in future proceedings.



Coastal Virginia Offshore Wind Demonstration Project.

Commodity Price Assumptions

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company 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 2021 Update, the Company utilized three commodity forecasts:

- RGGI + Federal CO_2
- RGGI + Federal CO_2 High Fuel Price
- RGGI + Federal CO_2 Low Fuel Price

These High and Low Fuel Price commodity forecasts utilize high and low natural gas supply scenarios from the United States 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 commodity case (i.e., the RGGI + Federal CO_2 commodity forecast).

A change in natural gas prices affects the energy price 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 driven by 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 all three commodity forecasts, the CO_2 price forecast is consistent with the methodologies utilized in the 2020 Plan. In all forecasts, Virginia is a member of RGGI starting in 2021 and a charge on CO_2 emissions from the power sector at the federal level is assumed to begin in 2026.

The Company utilized the RGGI + Federal CO_2 commodity forecast for all Alternative Plans, and the High and Low Fuel Price commodity forecasts to run sensitivities, which are described in ***Sensitivity Analyses***. Appendix 4O provides the annual prices (in nominal dollars) for each commodity price forecasts. Figure 4.3.1 provides a comparison of the three commodity forecasts with the base commodity forecast used in the 2020 Plan.

Figure 4.3.1: 2020 Plan vs. 2021 Update Fuel, Power, and REC Price Comparison

	2021-2035 Average Value (Nominal $)	2022-2036 Average Value (Nominal $)		
Fuel Price	**2020 Mid Case CO_2 With VA in RGGI**	**2021 RGGI + Fed CO_2 Case**	**2021 RGGI + Fed CO_2 High Fuel Price Case**	**2021 RGGI + Fed CO_2 Low Fuel Price Case**
Henry Hub Natural Gas ($/MMbtu)	4.05	3.61	6.00	3.40
Zone 5 Delivered Natural Gas ($/MMbtu)	3.68	3.18	5.57	2.97
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	74.20	62.94	63.46	62.92
1% No. 6 Oil ($/MMbtu)	11.52	9.91	10.52	9.04
Electric and REC Prices				
PJM-DOM On-Peak ($/MWh)	44.58	35.11	50.60	33.94
PJM-DOM Off-Peak ($/MWh)	34.78	30.46	46.71	29.40
PJM Tier 1 REC Prices ($/MWh)	9.13	9.84	6.39	10.21
RTO Capacity Prices ($/kW-yr)	57.34	64.98	40.80	66.13

Renewable Energy-Related Assumptions

Solar Capacity Factor

For Alternative Plans A through C, the Company modeled existing and future solar resources using a capacity factor of 21.2%, which is the average capacity factor of the Company's owned solar tracking fleet in the Commonwealth for the most recent 3-year period (i.e., 2018, 2019, 2020), as required by prior SCC orders.

The Company also ran a sensitivity on Alternative Plan B using a capacity factor of 25.4% for future solar resources, which is the average design capacity factor representing an average capacity factor over the life of the facility (i.e., not just three years), taking into account degradation. The results of that sensitivity can be seen in ***Sensitivity Analyses***.

Solar Company-Build vs. PPA

In all Alternative Plans, the Company limited the model to selecting a maximum of 1,200 MW 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-build cost-of-service solar or third-party PPA. For Alternative Plans B and C, the Company modeled solar PPAs as 35% of the solar generation capacity placed in service over the Study Period, which is consistent with the 2020 Plan and the VCEA.

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. The solar integration costs include three 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 reserves.

In this 2021 Update, the Company has revised its assumptions and, in some instances, refined its methodology. Notably, in the 2020 Plan, the Company only applies these costs to solar resources; in this 2021 Update, the Company also applies these costs to wind resources.

Transmission Interconnection Costs. In this 2021 Update, the Company assumed renewable energy interconnection costs of $89/kW for utility-scale solar facilities and $310/kW for distributed solar facilities. Consistent with the 2020 Plan, 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.

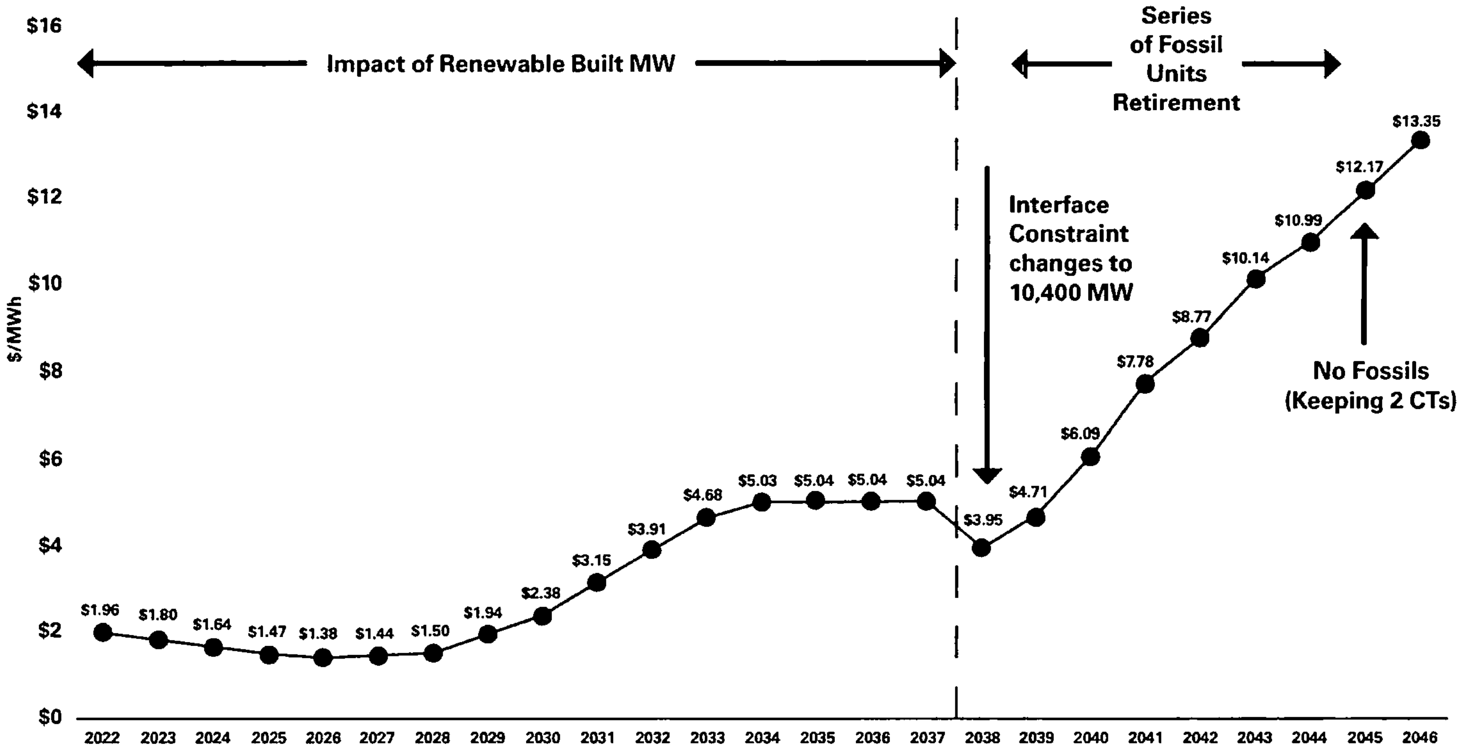
Generation Re-dispatch Costs. As explained in the 2020 Plan, re-dispatch generation costs are defined by the Company as additional costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. For the 2021 Update, improvements from the 2020 Plan were made to the variations on hourly generations to include solar and offshore wind generation, as well as to the methodology utilized in the generation re-dispatch cost analysis. For example, the Company took a chronological approach utilizing one build plan from the 2020 Plan (Alternative Plan D) with one fuel price set (2021 RGGI + Federal CO_2) and studied 16 years chosen based on when resources were introduced or retired in the build plan. For each simulation year, the Company performed a base case Aurora simulation by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, the Company performed an additional 200 simulations but applied different hourly renewable profiles from NREL's historical weather patterns studies to reoptimize the system cost.

Southampton Solar Farm; Southampton, VA.

The total system cost for each simulation was compared to the base case system cost of the same year. This delta of the system cost is composed of the respective differences in fuel, variable operation and maintenance costs, emissions, purchase/sale of energy and power costs. The re-dispatch cost is the delta of the system cost divided by the Company's expected total renewable generation. Based on these results, the Company constructed a generation re-dispatch cost curve for the entire Study Period, as shown in Figure 4.4.3.1. These values were used as a variable cost adder for all renewable energy generation evaluated in this 2021 Update.

Over time, the re-dispatch costs are projected to increase due to: (i) the increase of fuel and CO_2 prices in the 2021 RGGI + Federal CO_2 case, which resulted in higher DOM Zone prices; (ii) the retirement of dispatchable fossil generating facilities; and (iii) the increased penetration of renewables causing an increase in energy imbalance (excess or shortage) to meet the load obligation. If the energy imbalance was due to excess energy, the sale price trended lower, even close to zero, which reduced the sales revenues. If the imbalance was due to an energy shortage, the purchase price could be as high as $1,000/MWh (PJM price cap). This extreme results in an increase in purchase costs.

Figure 4.4.3.1: Generation Re-dispatch Cost Results ($/MWh)



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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 2021 Update is consistent with the 2020 Plan, but the analysis was updated with 2020 market information. Specifically, in 2020, the cost of regulating reserves averaged $0.22/MW, but the cost in specific hours ranged from $0.00 to over $73.00. The results of the analysis with these updated assumptions reflect that the hourly (per MW) cost of regulating reserves gradually increases from $0.52 in 2022, to $16.72 in 2046. This occurs because the rate that PJM is forecasted to increase the need for regulating reserves (driven by the level of renewable energy build) grows more quickly than the projected addition of resources that provide regulation reserves in PJM. Figure 4.4.3.2 to the right shows the net cost to customers included in this 2021 Update.

Least-Cost Plan Assumptions

Alternative Plan A presents a least-cost plan using assumptions required by the SCC. Specifically, Plan A uses the PJM Load Forecast adjusted for only existing and proposed energy efficiency. It meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA. As noted in ***PLEXOS Modeling Refinements***, the Company has refined PLEXOS to model the RPS Program, and allows the model to choose up to 100% of REC market purchases as needed to comply with the annual RPS Program requirements. For Plan A, the Company did not force the model to select any specific resources and did not exclude any reasonable resource options. That said, the model did include reasonable build constraints, including the 1,200 MW annual solar limit as well as a limit of one pair of simple cycle combustion turbines per year. The potential unit retirements shown in Plan A are those selected by PLEXOS, as discussed further in ***Existing Supply-Side Generation***.

Figure 4.4.3.2 – Company Net Regulating Reserves Cost of Market Purchases ($000,000)

Year	Plan A	Plan B	Plan C
2022	$0	$0	$0
2023	$0	$0	$0
2024	$0	$0	$0
2025	$0	$0	$0
2026	$0	$0	$0
2027	$0	$0	$0
2028	$0	$0	$0
2029	$0	$0	$0
2030	$0	$0	$0
2031	$0	$1	$1
2032	$0	$11	$11
2033	$0	$17	$0
2034	$0	$208	$174
2035	$0	$213	$163
2036	$0	$231	$161
2037	$0	$235	$137
2038	$0	$240	$113
2039	$0	$246	$88
2040	$0	$252	$19
2041	$0	$254	$0
2042	$0	$260	$0
2043	$0	$304	$0
2044	$0	$351	$0
2045	$0	$401	$0
2046	$0	$409	$0

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.