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

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-referenced matter the *Rebuttal Testimony of Virginia Electric and Power Company.*

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

Highest regards,

/s/ Vishwa B. Link

Vishwa B. Link

Enclosures

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WITNESS REBUTTAL TESTIMONY SUMMARY

Witness: Glenn A. Kelly
Title: Director, Integrated Strategic Planning

Company Witness Kelly addresses a number of areas in detail, including the modeling process; modeling assumptions; unit retirements; resource options; "least cost" plans; reliability; and forward capacity markets.

Mr. Kelly also responds generally to the testimony offered by Staff and respondents criticizing the 2020 Plan in many respects. As a general matter, the Company, the Commonwealth of Virginia, and the State of North Carolina have all committed to a cleaner energy future. The Company has already begun to transition its system—generation, transmission, and distribution—to achieve this cleaner future. It is important to recognize, however, that this future will require a fundamental and transformational change to the existing electric system, and likely cannot be accomplished over the long term based on today's technologies. As stated from the start of the 2020 Plan, over the longer term, achieving a cleaner energy future will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy.

In the Commonwealth, the commitment to a cleaner energy future is primarily embodied in the recently-effective VCEA. The VCEA recognizes that this transformational change to the existing system will not happen overnight, setting targets 15, 25, and even 30 years out. The General Assembly passed the VCEA in early March. On March 9, 2020, the Commission issued an order requiring the Company to model the costs and reliability impacts of the VCEA and other relevant legislation in the 2020 Plan. The final version of the VCEA was not signed into law by the Governor, though, until April 11, 2020. By statute, the Company was required to finalize and file the 2020 Plan less than three weeks later on May 1, 2020.

Staff and respondents provide criticisms of the Company for how it modeled the VCEA in the 2020 Plan, with some implying that the Company does not have the desire or the intention to determine a cost-effective path to meeting the targets and requirements of the VCEA. Company Witness Kelly disagrees with that implication. The VCEA is now the law of the Commonwealth, and the Company makes every effort to follow all applicable laws and regulations. Further, the Company, perhaps as much as any stakeholder, wants to determine a path to clean energy that meets public policy objectives while maintaining the standard of reliability that customers expect and deserve, and doing so at the lowest reasonable cost. Given the short turnaround to plan and model transformational changes, the Company had to make several simplifying assumptions in order to complete the required modeling for the 2020 Plan to meet the March 9 Order and to file by the statutory deadline.

There are comments and critiques offered by Staff and respondents about the 2020 Plan that are valid suggestions for future improvements. The Company is committed to additional analyses and process improvements in future integrated resource plans ("Plans") and intervening update filings ("Update Filings"), and work is already underway. Mr. Kelly's Rebuttal Schedule 1 provides a list of process improvements the Company is working to implement to its modeling

for future Plans and Update Filings, as well as assumptions the Company intends to update. His Rebuttal Schedule 1 also provides a list of additional analyses related to system operations and reliability that the Company will continue to work on, as discussed further by Company Witnesses Robert Thomas and Kyle Thomas. These improvements and analyses will now take time to implement. Accordingly, the Company asks the Commission to give guidance and direction for focus on future Plans and Update Filings, and to give the Company time to perform the necessary improvements and analyses.

Finally, Company Witness Kelly reiterates that job numbers one and two of the Company are safety and reliability. The Company must provide safe and reliable energy to our customers. The Company will refine these analyses over time to ensure reliability for our customers at the lowest reasonable cost.

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REBUTTAL TESTIMONY
OF
GLENN A. KELLY
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION
CASE NO. PUR-2020-00035

Q. Please state your name, business address, and position of employment.

A. My name is Glenn A. Kelly, and I am the Director – Integrated Strategic Planning for Dominion Energy Services, Inc., testifying on behalf of Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"). My business address is 600 East Canal Street, Richmond, Virginia 23219.

Q. Have you previously submitted testimony in this proceeding?

A. In lieu of pre-filed direct testimony, the Company submitted to the State Corporation Commission of Virginia (the "Commission") on June 1, 2020, a document that identified me as a witness who would appear and offer direct testimony at the evidentiary hearing in support of the Company's 2020 system-wide Integrated Resource Plan (the "2020 Plan"), specified those portions of the 2020 Plan that I adopt and sponsor, and attached a statement of my background and qualifications.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to address certain comments and recommendations offered by Gregory L. Abbott, David J. Dalton, and Earnest J. White on behalf of Commission Staff ("Staff"); by Scott Norwood on behalf of the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel"); by Rachel Wilson and Jason Frost on behalf of the Sierra Club; by Amanda Levin on behalf of the

Natural Resources Defense Council ("NRDC"); by Kerinia Cusick on behalf of Mr. Glen Besa ("Besa"); and by Karl Rábago on behalf of Appalachian Voices ("APV"). I will address a number of areas, including the modeling process; modeling assumptions; unit retirements; resource options; "least cost" plans; reliability; and forward capacity markets.

Q. Are you sponsoring any exhibits or schedules with your rebuttal testimony?

A. Yes. Company Exhibit No. __, GAK, consisting of Rebuttal Schedules 1 to 3, was prepared under my direction and supervision, and is accurate and complete to the best of my knowledge and belief.

Q. In addition to your pre-filed testimony, will the Company be presenting other rebuttal witnesses in this proceeding?

A. Yes, the Company is presenting the following additional rebuttal witnesses:

- Robert G. Thomas, Director of Corporate Strategy, responds to testimony on the load forecasting process and the development of solar integration costs.
- Mark D. Mitchell, Senior Vice President of Project Construction, responds to testimony on resource cost assumptions, solar capacity factor, energy storage, evaluation of future resources, and environmental justice.
- Edmund J. Hall, Manager of Energy Market Quantitative Analysis and Load Forecast, responds to testimony on the Company's modeling of demand-side management resources.
- M. Kyle Thomas, Manager of Electric Transmission Planning and Strategic Initiatives, responds to testimony regarding the Company's transmission planning process and related system reliability analyses.
- Robert S. Wright, Jr., Director of Distribution Grid Planning and Asset Management, responds to testimony related to the Grid Transformation Plan, and reiterates the steps the Company has taken toward integrated distribution planning.

- Maria Scheller, responds to the testimony of Staff Witness Bernadette Johnson, focusing on the natural gas price forecast and the power price forecast presented.
- Robert J. Trexler, Director of Regulation, responds to testimony on the Company's residential bill analysis and bill presentation.

Q. Mr. Kelly, do you have any initial comments in response to the testimony offered by Staff and respondents?

A. Yes, I do. The Company, the Commonwealth of Virginia, and the State of North Carolina have all committed to a cleaner energy future. The Company has already begun to transition its system—generation, transmission, and distribution—to achieve this cleaner future. It is important to recognize, however, that this future will require a fundamental and transformational change to the existing electric system, and likely cannot be accomplished over the long term based on today's technologies. As stated from the start of the 2020 Plan, over the longer term, achieving a cleaner energy future will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy.

In the Commonwealth, the commitment to a cleaner energy future is primarily embodied in the recently-effective Virginia Clean Economy Act (the "VCEA"). The VCEA includes provisions that institute a mandatory renewable energy portfolio standard program ("RPS Program"); incentivize the significant development of solar, wind, and energy storage; require the retirement of certain existing generation units, envisioning zero carbon by 2045, absent threats to reliability or security; and establish energy efficiency targets. In addition, other legislation from the 2020 Regular Session of the General Assembly authorizes Virginia to join the Regional Greenhouse Gas Initiative

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("RGGI"), a collaborative effort to cap and reduce carbon dioxide ("CO_2") emissions from the power sectors of participating states.

The VCEA recognizes that this transformational change to the existing system will not happen overnight, setting targets 15, 25, and even 30 years out. The General Assembly passed the VCEA in early March. On March 9, 2020, the Commission issued an order requiring the Company to model the costs and reliability impacts of the VCEA and other relevant legislation in the 2020 Plan (the "March 9 Order"). The final version of the VCEA was not signed into law by the Governor, though, until April 11, 2020. By statute, the Company was required to finalize and file the 2020 Plan less than three weeks later on May 1, 2020. Staff Witness Abbott recognized this challenging timeframe, seeming to acknowledge the difficulty in modeling the VCEA within this short period of time.

Staff and respondents provide heavy criticisms of the Company for how it modeled the VCEA in the 2020 Plan, with some implying that the Company does not have the desire or the intention to determine a cost-effective path to meeting the targets and requirements of the VCEA. I wholeheartedly disagree with that implication. The VCEA is now the law of the Commonwealth, and the Company makes every effort to follow all applicable laws and regulations. Further, the Company, perhaps as much as any stakeholder, wants to determine a path to clean energy that meets public policy objectives while maintaining the standard of reliability that customers expect and deserve and doing so at the lowest reasonable cost. Given the short turnaround to plan and model transformational changes, the Company had to make several simplifying assumptions in order to complete the required modeling for the 2020 Plan to meet the March 9 Order and to file by the statutory deadline.

That said, there are comments and critiques offered by Staff and respondents about the 2020 Plan that are valid suggestions for future improvements. The Company is committed to additional analyses and process improvements in future integrated resource plans ("Plans") and intervening update filings ("Update Filings"), and work is already underway. We are all learning and understanding what is needed to safely, reliably, and affordably transition to a cleaner future over the next 30 years. This transition is a marathon, not a sprint; and the 2020 Plan represents mile one. The Company respectfully requests the Commission to recognize as much, and to approve the 2020 Plan as reasonable and in the public interest for the specific and limited purpose of filing the planning document mandated by the Code of Virginia ("Va. Code"). The Company expects and welcomes the Commission's direction regarding the complex requirements of the VCEA, and believes the final order in this proceeding will help guide the Company preparing its future Plans and Update Filings. I would also note that several other proceedings are underway that will further inform future Plans on certain topics, such as the ongoing energy storage regulations proceeding in Case No. PUR-2020-00120.

Q. You mentioned that the Company is committed to additional analyses and process improvements, could you elaborate?

A. Yes. There was much focus on the modeling completed for this 2020 Plan, which I will discuss in more detail below. My Rebuttal Schedule 1 provides a list of process improvements the Company is working to implement to its modeling for future Plans and Update Filings, as well as assumptions the Company intends to update. My Rebuttal Schedule 1 also provides a list of additional analyses related to system operations and

reliability that the Company will continue to work on, as discussed further by Company Witnesses Robert Thomas and Kyle Thomas.

Q. Do you have any other initial comments before turning to specific issues?

A. Yes. I need to reiterate that job numbers one and two of the Company are safety and reliability. The Company must provide safe and reliable energy to our customers—our customers expect and deserve it. The Company described some of the reliability concerns it has over the long term, which Staff Witness Michael A. Cizenski seems to echo. While additional analyses are needed, the blackouts and reliability issues going on in California are a good indication that problems can occur. The Company will refine these analyses over time to ensure reliability for our customers at the lowest reasonable cost.

Q. Mr. Kelly, how is your testimony organized?

A. My rebuttal testimony is organized as follows:

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I. PLEXOS MODELING, GENERALLY

Q. Staff and respondents focus heavily on PLEXOS modeling. Can you provide a high-level overview of PLEXOS?

A. Yes. PLEXOS is an energy market simulation software produced by Energy Exemplar that is designed to optimize a wide range of variables including market pricing, unit dispatch, and resource adequacy, including both capacity and energy needs. PLEXOS can be used to determine new resource additions and retirements, as well as least-cost unit dispatch. At its core, the PLEXOS dispatch algorithms determine the least-cost dispatch plan given the available resources, assumptions, and constraints placed on the model. Many organizations in the United States and abroad use or have used PLEXOS, including PJM Interconnection, LLC ("PJM").

PLEXOS has the capability to incorporate many concepts inherent in the energy market. Before using such capabilities, however, PLEXOS must be configured to represent the specific constraints, and then validated. In addition, software users must learn how the constraints operate in order to determine if the new constraints cause any unforeseen impacts. Often, this involves collaboration with the software developers to resolve these issues and verify the constraints are working as designed. For example, while PLEXOS has the capability to model renewable energy portfolio standard ("RPS") programs generally, it would need to be configured to incorporate the unique constraints of the RPS Program established by the VCEA, such as calculating the annual renewable energy certificates ("REC") requirements based on a percentage of non-nuclear electric energy sold to retail customers in the Company's service territory, including retail customers purchasing from competitive service providers.

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Q. What was different about the PLEXOS modeling completed for the 2020 Plan compared to prior Plans?

A. As I noted above, the Company had less than two months to model the VCEA in accordance with the March 9 Order; validate the results; and finalize and file its 2020 Plan by the statutory deadline. Prior to March, the PLEXOS model used by the Company was not configured to incorporate the many provisions of the VCEA. Given the short timeframe, the Company determined that it did not have time to re-configure and validate PLEXOS. To meet the statutory deadline and the March 9 Order, the Company used other tools and processes to determine possible alternative resource plans, enter the results into PLEXOS, and then use PLEXOS to determine the least-cost dispatch of these resources. In this way, PLEXOS was used to determine the net present value ("NPV") of each alternative plan. While this relies on certain simplifying assumptions, the Company did not see any alternatives based on the timeframe.

Q. Please explain the process the Company used to determine alternative resource plans.

A. For existing units, the Company followed the same process to evaluate potential unit retirements that it has in prior Plans while also taking into account the new mandates in the VCEA related to unit retirements. I will discuss retirements in more detail later in my testimony. For new units, the Company started with the language of the VCEA, which declared to be in the public interest 16.1 gigawatts ("GW") of solar or onshore wind; 5.2 GW of offshore wind; and 2.7 GW of energy storage. For requirements over certain periods of time, the Company followed a reasonable annual glide path to meet the specific target. Of the 2.7 GW of energy storage, the VCEA specified that the Company

may procure a single energy storage project up to 800 MW, allowing for the construction of a pumped hydroelectric storage facility as envisioned by prior legislation from the 2017 Regular Session of the General Assembly. Because of this carve out, the Company included the 300 MW pumped storage project currently in the early stages of development. The Company also factored in resource characteristics as needed. For example, the Company added additional battery energy storage systems ("BESS") at the end of their ten-year operating life.

The VCEA also established the RPS Program under which the Company must meet annual requirements for the sale of renewable energy based on a percentage of non-nuclear electric energy sold to retail customers in the Company's service territory. Accordingly, the Company manually calculated its projected annual RPS Program requirement, making assumptions as needed based on the complexities of the RPS Program on what does or does not count as "total electric energy" under Va. Code § 56-585.5.

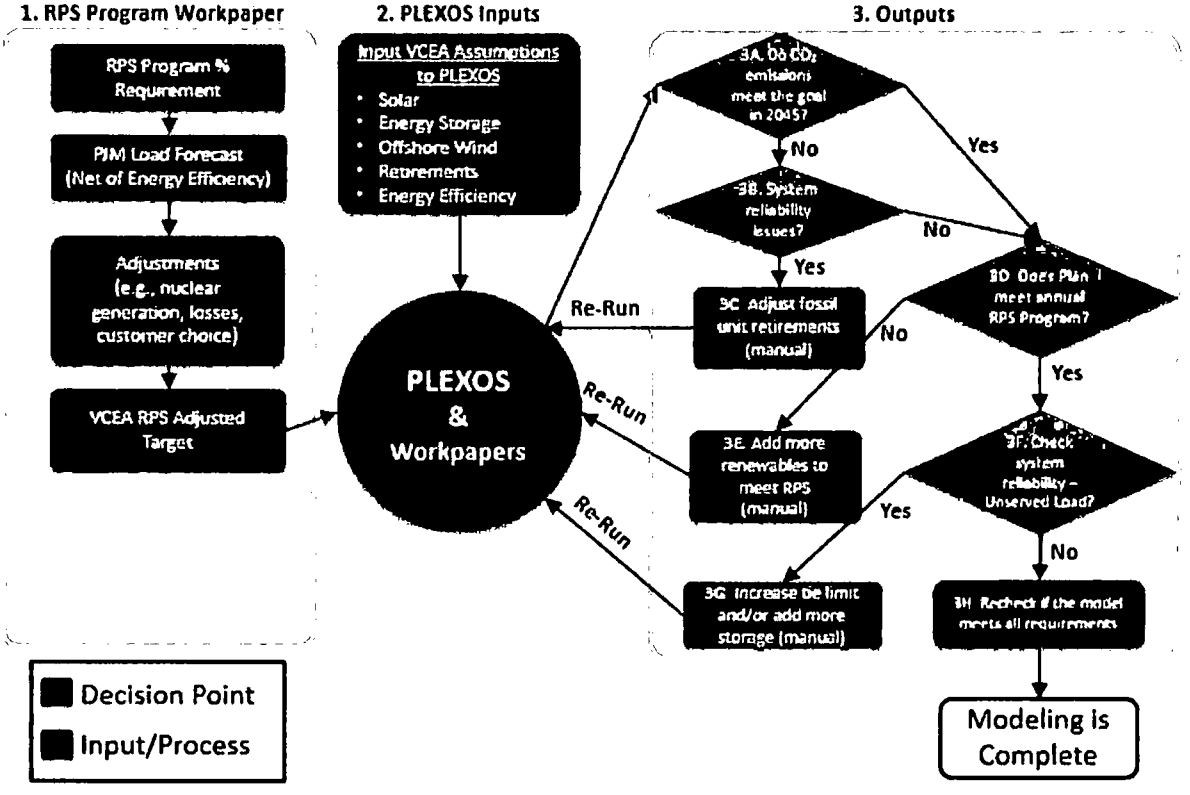
The Company incorporated this resource plan into PLEXOS, which also incorporated a load forecast adjusted to account for the energy efficiency targets established in the VCEA, and then ran PLEXOS. The Company took the results (*i.e.*, the projected dispatch of these resources) and determined whether its renewable resources produced sufficient RECs to meet the annual RPS Program requirements. To the extent not enough RECs were produced, the Company iteratively added solar resources to the resource plans as needed to meet the RPS Program requirements. The Company added solar resources based on the results of its busbar screening tool, which identified solar as the least cost renewable resource available (the only other option was onshore wind).

Once the RPS Program annual requirements were met, the Company evaluated the results for reliability concerns and added resources as needed to address those concerns. For example, the Company added 970 MW of combustion turbines ("CTs") as a placeholder to address probable system reliability issues resulting from the significant renewable energy resources and the retirement of traditional synchronous generator facilities, among other things. The Company also added additional energy storage to eliminate any unserved energy shown in PLEXOS (*i.e.*, blackouts).

As discussed in more detail in the 2020 Plan and in the rebuttal testimony of Company Witness Kyle Thomas, and based on existing technology, the Company has concerns about reliability if the Company were to retire all Company-owned carbon-emitting generation by 2045. Accordingly, the Company developed alternatives if the Company were to (1) preserve some of these units for reliability (*i.e.*, Alternative Plans B and B_{19}), or (2) retire all Company-owned carbon-emitting generation by 2045 based on a reasonable glide path (*i.e.*, Alternative Plans C and D).

Rebuttal Figure 1 below provides a graphic of this process.

Rebuttal Figure 1: VCEA Modeling Process in 2020 Plan



1 **Q. Overall, many of the respondents conclude that the Alternative Plans presented in**
2 **the 2020 Plan are not the result of least-cost optimization. Do you agree?**
3 A. Only partially. While PLEXOS could not be configured in time to determine the
4 resource plans on its own, the Company did use PLEXOS to simulate dispatch of these
5 resources and to derive the NPV of each alternative plan. I do believe the process
6 described above produced a reasonable set of alternative plans given the goals and
7 requirements established by the VCEA.

8 **Q. Staff and respondents generally criticize the Company for forcing PLEXOS to select**
9 **certain resources. Please comment.**
10 A. I have explained why the timeframe for preparing the 2020 Plan resulted in the Company

modeling the 2020 Plan with certain simplifying assumptions. The Company is working with Energy Exemplar (the PLEXOS software developer) to refine the model to be able to incorporate the many requirements of the VCEA. My Rebuttal Schedule 1 includes a list of the refinements the Company is working to incorporate in future Plans and Update Filings.

I would also note that the modeling performed by Sierra Club Witness Wilson and NRDC Witness Levin produced results that are similar to those produced by the Company's manual process (depicted in my Rebuttal Figure 1). For example, the results of all three modeling efforts included a significant volume of solar resources; a significant volume of BESS; a pumped storage facility; 2.6 GW of offshore wind; either additional offshore wind or some onshore wind; nuclear license extensions for all four of the Company's existing nuclear units; and natural gas units remaining in service. Many of the differences come down to timing and the exact volume of solar resources. The similarities between the modeling efforts in this proceeding confirm that the Company's 2020 Plan is reasonable as a first step in modeling the VCEA.

Q. APV Witness Rábago states on pages 25 and 26 of his testimony that "[t]rue resource optimization requires modeling in small time increments such as 15 minutes or 5 minutes, at scales down to 1 kilowatt, and at a geographic resolution of just a few square kilometers," and that "[a] resource planning model should also be able to choose from all resources, not just generators." Do you have any comment?

A. What Mr. Rábago is discussing was not possible in the timeframe the Company had to model the requirements of the VCEA, nor is it realistic for a 25-year annual modeling exercise for a bulk power system covering multiple states. That said, the Company

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intends to incorporate several modeling improvements into future Plans and Update Filings, as shown in my Rebuttal Schedule 1. In addition, Company Witness Wright discusses the Company's efforts toward integrated distribution planning, which does evaluate the system at a higher resolution.

Q. Aside from the general modeling process used for the 2020 Plan, Staff Witness Abbott criticizes the lack of transparency on pages 11 to 16 of his testimony, characterizing PLEXOS as a "black box." He first argues that "only the Company possesses the model and has the expertise to run various scenarios under differing model assumptions." Please comment.

A. I disagree with this statement. Indeed, it is clear from the testimony of Sierra Club Witness Wilson and NRDC Witness Levin that others have the expertise to complete utility modeling. While the Company conceded that Staff does not have a license to PLEXOS software, the Company does not believe this obligates the Company to run any scenario or use any assumption that Staff would like to test. This is especially true for this 2020 Plan where—unlike the 2018 Plan to which Staff Witness Abbott refers—significant manual processes were required, as discussed above.

Q. Staff Witness Abbott also argues that "only the Company possesses the detailed input files that are used in the model simulations." Do you agree?

A. No, I strongly disagree. The Company received 69 sets of discovery in this proceeding, totaling over 600 questions, many with multiple subparts. The Company provided the inputs requested, including requested data on existing units that Mr. Abbott claims on page 12 that the Company did not provide. Indeed, Sierra Club Witness Wilson used these inputs to conduct their own modeling. The recommendation to "require the

Company to provide all input files that are used in the PLEXOS modeling" is impractical and unnecessary. To the extent the Company does not provide inputs in future proceedings, the Commission has a robust discovery process in place to address any concerns.

Q. Staff Witness Abbott notes the "lack of sensitivity runs" on page 14 of his testimony, and on page 16 recommends that the Commission require the Company to perform "numerous sensitivity analyses" in future Plans, such as for high and low PJM energy prices, high and low PJM capacity prices, high and low construction costs, and high and low fuel prices. Please comment.

A. I would first note that the Company did provide sensitivities in the 2020 Plan. Alternative Plans B and B_{19} showed the results of altering the solar capacity factor from 25% to 19%. In Figure 4.1.2.1 of the 2020 Plan, the Company showed the results of a sensitivity using a different load forecast. In Figure 4.4.1, the Company showed the results of sensitivities using different commodity forecasts. Accordingly, it is not correct to say that the 2020 Plan lacked sensitivities.

That said, the Company does not oppose presenting sensitivities in future Plans. My Rebuttal Schedule 1 includes a list of sensitivities, including those that the Company is already obligated to provide (*e.g.*, solar capacity factor) and those suggested by Staff Witness Abbott that the Company believes are reasonable.

II. VCEA AND OTHER 2020 LEGISLATION MODELING ASSUMPTIONS

Q. Turning to testimony on specific modeling assumptions related to the VCEA and other 2020 legislation, NRDC Witness Levin states on page 9 of her testimony that the Company did not model the requirements of the mandatory RPS Program implemented through the VCEA. Do you agree?

A. No, I do not. As I explain above, the Company manually calculated its projected annual RPS Program requirement, determined whether the resource plan produced sufficient RECs to meet the annual RPS Program requirement, and then added solar resources to the resource plan as needed to meet the RPS Program requirements. Through discovery (DEV to NRDC Set 2-5), Ms. Levin seemed to clarify that she takes issue with how the Company modeled the RPS Program, not whether the Company modeled the RPS Program. This response is included in my Rebuttal Schedule 2.

Q. Staff Witness Dalton takes issue with how the Company modeled the RPS Program. First, on page 45, he discusses the concern that Plan B_{19} and D appear to produce RECs in excess of those needed for RPS Program compliance. Second, on page 46 to 47, Staff Witness Dalton discusses his concern that the Company's modeling does not appear to optimize RPS Program compliance by banking RECs. Please comment.

A. The Company must do much more than meet the requirements of the RPS Program—it must run its system 24 hours a day, 365 days a year. As discussed more below, many of the new resources, especially in the last ten years of the twenty-five year study period, are built to serve customers' energy and capacity needs, not just to produce RECs for RPS Program compliance.

Witness Dalton criticizes the Company for not monetizing or banking excess RECs in its modeling. This is valid feedback. Banking RECs is one of the complexities of the RPS Program that prevented the Company from re-configuring PLEXOS in the timeframe available to model many aspects of the VCEA. The Company will work to incorporate this option into future Plans and Update Filings. To be clear, it is the Company's intention to optimize the value of RECs produced from its portfolio of renewable energy resources, to the extent possible, in order to meet the RPS Program requirements in the least cost manner.

Q. On page 48 of his testimony, Staff Witness Dalton states that because the Company did not model possible RPS Program deficiency payments, the Company was not fully responsive to the directive to model the VCEA. Do you have any comment?

A. I do. The deficiency payments in the RPS Program were another complexity of the RPS Program that prevented the Company from re-configuring PLEXOS in the timeframe available to model many aspects of the VCEA. This is especially true because the VCEA provides for different deficiency payments based on the size of resource (*i.e.*, $75 per megawatt-hour ("MWh") related to the distributed energy resource ("DER") requirement, and $45 per MWh for the remainder). Nevertheless, the Company will evaluate how to incorporate this option into future Plans and Update Filings. That said, the Company's assumption that the Company could build resources or purchase RECs for less than the deficiency payment was a reasonable assumption for the 2020 Plan, so I disagree with Witness Dalton's statement that the Company did not meet the requirements of the March 9 Order.

Q. On pages 9 to 15 of her pre-filed testimony, NRDC Witness Levin criticizes the Company for how it modeled carbon regulations, testifying in part that the Company did not include "any VCEA-required carbon limits." Please comment.

A. As an initial matter, I disagree that the VCEA itself sets any specific limits on carbon allowances until at least 2050. As discussed in Section 1.3 of the 2020 Plan, Virginia will join RGGI in 2021 based on enabling legislation from earlier this year and subsequent actions by the Virginia Department of Environmental Quality. But I do not believe that RGGI represents a "carbon limit" as Witness Levin has used the phrase. RGGI is a market-based "cap and trade" program—not just a "cap" program. While all states in RGGI set annual emissions caps that decline over time, this generally represents the volume of CO_2 allowances that are offered through the RGGI auction for a specific year. Regulated sources (*i.e.*, the carbon-emitting generating units that are subject to RGGI) must then purchase a CO_2 allowance for every CO_2 short ton emitted during a specific compliance period. Accordingly, to model carbon regulations in the 2020 Plan, the Company added a forecasted cost of CO_2 allowances to its generating units in Virginia subject to RGGI. The Company believes this was the appropriate method to model carbon regulations based on the nature of RGGI.

Through discovery (DEV to NRDC Set 2-26(j)), the Company understands that NRDC Witness Levin modeled all of the RGGI states to determine the CO_2 allowance price based on the applicable limits. This response is included in my Rebuttal Schedule 2. ICF follows a similar process in developing its RGGI CO_2 allowance price forecast that it provides to the Company for use in its modeling.

Q. Consumer Counsel Witness Norwood (page 18) and NRDC Witness Levin (page 17) question the Company for forcing the model to select 16 GW of utility-scale solar resources and 2.7 GW of energy storage. Why did the Company model these provisions of the VCEA as it did?

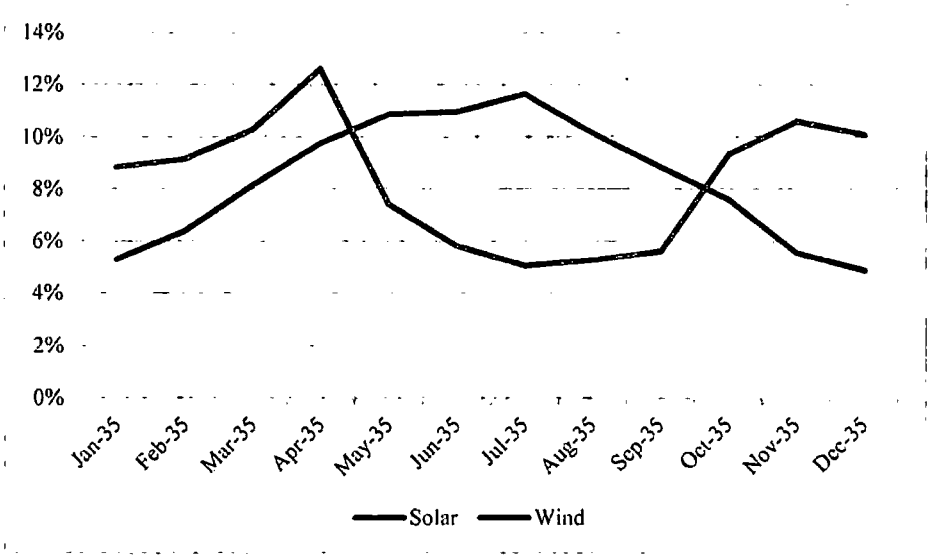
A. As discussed earlier, the VCEA found 16.1 GW of solar (or onshore wind) and 2.7 GW of energy storage to be in the public interest. In addition, the VCEA requires the Company to petition the Commission for the necessary approvals for this level of capacity. Another portion of the statute refers to this as "the utility's procurement requirements." While I will leave questions of statutory interpretation raised by respondents to the lawyers and, ultimately the Commission, the Company made the assumption that each alternative plan should model the level of capacity outlined in the VCEA. This is similar to the approach the Commission has directed related to energy efficiency, where the Grid Transformation and Security Act of 2018 required only that the Company *propose* $870 million in spending on energy efficiency programs, but the Commission directed the Company to model this full amount, regardless of whether future unknown programs would be approved by the Commission.

Q. Staff Witness Dalton states on page 37 of his testimony "it would have been appropriate for the Company to develop at least one plan that substitutes additional solar resources in place of the 2,556 MW second tranche of planned offshore wind resources." Please respond.

A. As an initial matter, the Company did develop four plans at the request of Staff that removed the second tranche of offshore wind, providing the results of two of these plans in July 2020. I have explained above why the Company included 5.2 GW of offshore

wind, but I want to also highlight that solar and offshore wind resources have different production profiles, so are not an equivalent replacement as suggested by Mr. Dalton. Offshore wind produces more energy (*i.e.*, has a higher capacity factor) throughout a typical day, including at night when solar resources cannot produce energy. In addition, solar resources generate more in the summer while offshore wind resources tend to generate more in the winter. My Rebuttal Figure 2 compares the annual production profiles of solar and offshore wind.

Rebuttal Figure 2: Annual Production Profile of Solar and Offshore Wind



Therefore, these two resources are actually complementary, not one-for-one replacements. Solar and offshore wind resources also differ in terms of land use considerations. Solar resources require approximately 10 acres of land per MW of nameplate capacity. This land could be farmland or even woodlands that are cleared in order to provide the necessary acreage for the solar installation. By contrast, offshore wind can be sited more than 20 miles off the coast in existing leased areas owned by the

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federal government. Accordingly, replacing 2.6 GW of offshore wind with solar resources would require approximately 26,000 acres for the nameplate equivalent or approximately 43,680 acres for the energy equivalent.

Q. Similarly, on page 38 of his testimony Staff Witness Dalton states that "it would have been more appropriate for the Company to have developed at least one plan that substitutes 300 MW of [BESS] for the 300 MW of pumped storage facilities included in the model." Please respond.

A. Again, the Company developed four plans at the request of Staff that removed the 300 MW pumped storage facility, and I have explained why the Company included this resource in its alternative plans. But I want to highlight that BESS and pumped storage are not an equivalent resource for which a megawatt for megawatt replacement is appropriate. For example, BESS typically have shorter discharge duration than longer duration pumped storage (*e.g.*, the Company modeled a 4-hour duration for BESS and a 10-hour duration for pumped storage). Pumped storage facilities also typically have a longer useful life than BESS. Besa Witness Cusick discussed and acknowledged these differences between BESS and pumped storage on pages 6 to 9 of her pre-filed testimony. Accordingly, 300 MW of BESS is not an equivalent replacement for 300 MW of pumped storage as suggested by Mr. Dalton.

Q. On page 18 of his pre-filed testimony, Consumer Counsel Witness Norwood criticizes the limitation of solar power purchase agreements ("PPAs") to 35%. Why did the Company model this limitation?

A. The VCEA requires a split of 65% Company-owned solar and 35% PPAs. For example, Va. Code § 56-585.5 D 2 (a) says "35 percent of such generating capacity procured shall

be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by [the Company]." In the real world, there will be "lumpiness" based on the size of solar resources (*i.e.*, the solar resources come in certain increments that, when installed, may go slightly under or over the split in certain years), but the Company plans to get as close to the 65% / 35% split as possible at each interim target.

III. UNIT RETIREMENTS

Q. Staff and many respondents provide testimony about the existing generation unit retirements incorporated into the 2020 Plan, focusing on the results of the financial analysis performed by the Company. Could you begin by explaining what this financial analysis is, and what it is not?

A. Yes. The financial analysis is a ten-year cash flow analysis that evaluates the continued operation of specific existing generation units by comparing estimated fixed and variable costs against projected revenue for the next ten years based on the snapshot in time when the analysis was conducted. This analysis allows the Company to view each unit's near-term projected revenue and cost streams in one place, and to determine key drivers for unit profitability. A positive NPV result indicates that the unit is currently better than market, while a negative value indicates the unit is currently worse than market. Notably, this analysis focuses on the near-term operation of the units evaluated, not necessarily on the remaining life of the units.

The Company uses the results of this analysis in part to determine how best to continue operating a specific unit or group of units. For example, for units showing negative

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NPVs, the Company may look for cost-cutting measures for fuel or O&M. As another example, the Company may use these results to determine whether to move forward with certain large capital expenditures. The Company also uses the results of this near-term analysis to inform the tentative unit retirement dates shown in integrated resource plans. Importantly, however, for newer units, these results alone are not comprehensive and cannot exclusively be used to determine whether to continue to operate an existing unit. Other quantitative and qualitative considerations must be prudently factored into such determinations, such as remaining useful life, capacity and energy replacements, system reliability, personnel, impact of continued operation of the unit(s) on the local economy, and legislative restrictions, to name a few.

In past years, the Company has completed the near-term financial analysis primarily for its older generation units. This year, the Company included some newer units that emit CO_2 in the analysis—such as the Virginia City Hybrid Energy Center ("VCHEC")—to see the result of continued operations based on anticipated carbon regulations. For these newer units, the focus of the analysis was on how best to continue operating the unit to extract the most value for customers.

Q. Turning to specific generation units, Staff Witness Abbott (page 28), Staff Witness Dalton (page 15), and Consumer Counsel Witness Norwood criticize the Company for showing VCHEC as retiring in 2045, despite negative NPV results in the financial analysis performed by the Company. Please explain.

A. VCHEC is an approximately 600 MW facility in southwestern Virginia that burns coal, waste coal (also referred to as gob coal), and waste wood (*i.e.*, biomass). By reclaiming and using gob coal—a by-product of coal mining that leaches metals and other pollutants

into waterways—VCHEC has helped to improve environmental conditions in southwestern Virginia, including regional water quality. Following legislation from the 2007 Regular Session of the General Assembly that incentivized its construction, the Commission approved the construction of VCHEC in March 2008 in Case No. PUR-2007-00066. VCHEC entered commercial operation in July 2012, and has an anticipated useful life of 55 years. As a dispatchable unit, VCHEC can also provide reliability benefits as the Company continues to add more intermittent generation to its system. VCHEC supports jobs for 153 full-time employees, as well as an estimated 350 to 400 additional jobs in the region. In addition, VCHEC contributes between $40 million and $100 million annually to the local economy based on how it is dispatched, including $8.5 million in taxes to Wise County and the Town of St. Paul. I would also note that VCHEC is carbon capture compatible if and when the technology evolves to make implementation cost effective and commercially viable.

The Company included VCHEC in its near-term financial analysis for the first time this year to determine how best to continue operating the unit, not to determine whether or when to retire the unit. Not only is VCHEC less than ten years old, but the VCEA explicitly carved out VCHEC to allow for its continued operations until 2045, presumably in recognition of its age and of the benefits it provides both to the local economy and to the Commonwealth's land and water cleanup efforts, among other factors.

Q. Does the negative NPV for VCHEC in the financial analysis mean that it is economic to retire the unit?

A. No, not necessarily. As I explained, the financial analysis looked only at the costs of

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continuing to operate VCHEC for the next ten years. This analysis does not reflect other substantial costs to customers if the Company were to retire the unit. Most notably, the analysis does not factor in recovery of the remaining book value of this new generation unit, which is approximately $1.3 billion. It also does not factor in the costs of facilities that may be needed to replace the capacity and energy provided by VCHEC.

While the PLEXOS model is not currently configured to and thus was not used to determine the potential timing of the retirement of VCHEC, as I will discuss further below, Sierra Club presented modeling that attempted to do so. As explained by Sierra Club Witness Wilson on page 16 of her testimony, the modeling performed by Sierra Club showed VCHEC operating through 2031. This modeling appears to support the continued operation of VCHEC from a financial perspective in the near term.

Q. Staff also criticizes the retirement of three biomass units—Altavista, Hopewell, and Southampton (the "Biomass Units")—in 2028, despite negative NPV results in the financial analysis. Please explain the rationale for the 2028 tentative retirement date.

A. As with VCHEC, the results of the financial analysis do not necessarily mean that it is economic to retire these units, which were converted to burn biomass in 2013 as part of the transition to a cleaner energy generation fleet. In addition, the VCEA explicitly carved out the Biomass Units to allow for their continued operations until 2028, again presumably recognizing the benefits of continued operations.

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1 **Q. Staff Witness Dalton questions the retirement of Chesterfield Units 5 & 6 in 2023 as**
2 **too early (page 14), while Sierra Club Witness Wilson presents modeling showing**
3 **these units retiring in 2021 (page 15). Please comment.**
4 A. As to Ms. Wilson's suggestions to retire Chesterfield Units 5 & 6 sooner, these units are
5 committed to PJM capacity market through May 31, 2022.

6 As to why the Company decided to retire Chesterfield Units 5 & 6 in 2023, these units
7 entered commercial operation in 1964 and 1969, respectively, and are approaching the
8 end of their operating lives. The financial analysis showed an NPV of negative $78
9 million under the base case. As noted by Staff Witness Dalton, the estimated
10 transmission and distribution ("T&D") impact from the retirement of Chesterfield Units 5
11 & 6 at the time of the financial analysis was $100 million, but subsequent analysis by
12 PJM resulted in an actual T&D impact of approximately $22 million.[1] Combining this
13 actual T&D impact with the results of the financial analysis results is an NPV of negative
14 $56 million—not an NPV of positive $22 million as Mr. Dalton shows in his Table 2.

15 In addition, the Company would have had to make major environmental investments in
16 2023 to comply with the Clean Water Act if it did not retire these units. It would not
17 make sense to make additional major capital investments in 2023 when the VCEA

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[1] Staff Witness Dalton incorrectly states in footnote 44 on page 14 of his pre-filed testimony that "no transmission and distribution costs would be required." The letter from PJM referred to by Mr. Dalton actually states that PJM and the affected transmission owner found "reliability concerns . . . resulting from the deactivation of Chesterfield 5 & 6 generating units," but had put "operational measures in place to keep the transmission system reliable." The "affected transmission owner" here is the transmission function of the Company, and these "operational measures" involve the transmission solution with an estimated cost of approximately $22 million. I have attached the discovery responses the Company provided to Staff to explain this process as my Rebuttal Schedule 3.

requires they be retired by 2024. For all these reasons, the Company submitted a deactivation notice to PJM in February 2020 for Chesterfield Units 5 & 6 stating its intention to retire these units no later than May 31, 2023. This projected retirement year is consistent with what the Company has shown in prior plans, which maintains consistent messaging for personnel at these units and for the community.

Q. Staff Witness Dalton also questions the retirement of Rosemary in 2027, suggesting that this unit should run for longer. Do you have any comment?

A. I do. Rosemary entered commercial operations in 1990; 2027 is the end of the projected book life of Rosemary based on the most recent depreciation study. While the Company will likely continue to operate Rosemary if possible, we do not believe it is prudent to plan for this unit to operate beyond its estimated useful life.

Q. Sierra Club Witness Wilson recommends on page 29 of her pre-filed testimony that the Commission require the Company to develop "a robust estimate of the sustaining capital costs to maintain" VCHEC and Mt. Storm. Please comment.

A. This requirement is not necessary because the Company does develop a robust estimate of capital and fixed O&M costs for its existing fleet as part of the financial analysis described above, including but not limited to environmental, operational, staffing, maintenance, outage, and capital assumptions.

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1 **Q. Sierra Club Witness Wilson (pages 28 and 29) and APV Witness Rábago (page 14)**
2 **testify that the Company should allow PLEXOS to select unit retirements, rather**
3 **than completing an analysis outside of PLEXOS and then inputting the results.**
4 **Please comment.**
5 A. I agree there is value in letting PLEXOS inform the tentative retirement dates of existing
6 base load and intermediate units. However, PLEXOS is not currently configured to
7 select unit retirement dates or account for all costs. While PLEXOS cannot consider
8 qualitative benefits, if configured, it would account for economic factors, such as
9 dispatchability and replacement capacity and energy. The Company will work to
10 configure PLEXOS to allow it to select the economic timing of unit retirements in future
11 Plans. Combining this data with qualitative factors can provide a more comprehensive
12 retirement analysis for the units evaluated. This should meet Staff Witness Dalton's
13 recommendation on page 17 of his testimony to follow economic signals in determining
14 retirements shown in future Plans, and Consumer Counsel Witness Norwood's
15 recommendation on page 25 of his testimony for the Company to reassess its retirement
16 analysis.

17 **Q. One final question regarding the process for determining unit retirements for**
18 **purpose of integrated resource planning. On page 27 of his testimony, Staff Witness**
19 **Abbott recommends that for any future generation unit retirement analysis each**
20 **individual unit be evaluated separately. Do you have any comment?**
21 A. I do. The Company analyzes certain units jointly when units share a large amount of
22 common expenses. For example, Chesterfield Units 5 & 6 share expenses related to the
23 coal yard, ash disposal, water treatment, air compressor, administration facilities, and

personnel. The same can be said of Clover Units 1 & 2. If the proportional amount of common expenses is borne only by one unit rather than two, it adversely affects the NPV of the remaining unit. For these reasons, I believe it is prudent to continue to evaluate these units jointly.

IV. RESOURCE OPTIONS AND RELATED ASSUMPTIONS

Q. Many respondents provide testimony on resource options included or not included in the 2020 Plan. For context, can you explain the relationship between the results of the Company's busbar analysis and the Company's PLEXOS modeling?

A. Yes. Before modeling new Company-owned resources in PLEXOS, the Company uses a high-level screening tool—referred to as the busbar—to determine which generation technologies are competitive on a levelized cost of energy ("LCOE") basis. For potential Company-owned resources where the resource cost depends upon a specific project, such as offshore wind and pumped storage, the Company includes the resource in the busbar to the extent it has project-specific information.

Not all resources that are screened in the busbar are chosen to be modeled in PLEXOS. The Company screens out resources that are not mature technologies and those that are uneconomic compared to other new resource options. Screening out resources through the busbar helps to reduce the PLEXOS model run time without decreasing the accuracy of the results. If a potential Company-owned resource is mature enough, has detailed cost and performance data, and has a reasonable LCOE, the Company includes the potential Company-owned resource in its PLEXOS modeling.

Notably, the busbar analysis focuses on potential Company-owned resources. The Company separately determines estimated costs for potential third-party resources—notably solar PPAs—and includes those resource options in PLEXOS.

While the LCOE presented through the busbar provides a useful data point, it does not provide a full picture of which potential resources may be the best option for customers because the LCOE focuses only on the construction and operating costs of a given resource, not the benefits. While capacity resources like BESS and CTs may have higher LCOEs, they help to meet peak loads and resolve reliability issues.

Q. APV Witness Rábago criticizes the Company on page 13 of his testimony for not including solar PPAs in its busbar analysis, and representing that as a possible "cause of higher than necessary NPV costs." Do you have any comment?

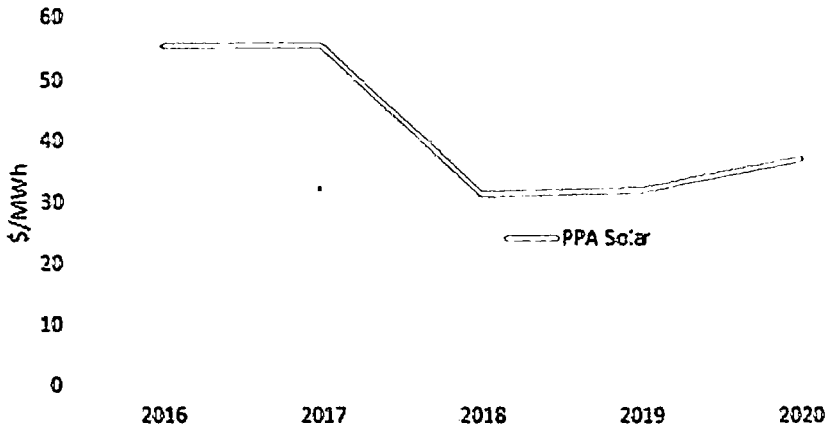
A. I do. This statement represents a misunderstanding of the process used by the Company. As explained, the busbar focuses on potential Company-owned resources. Separately, the Company includes third-party PPAs as options in PLEXOS to the extent it has cost information available. Alternative Plan B, for instance, includes 5,160 MW of solar PPAs through 2035. Excluding PPAs from the busbar screening tool has no bearing on the NPV results in the final alternative plans.

Q. Turning to specific resources, NRDC Witness Levin (page 20) and Sierra Club Witness Wilson (pages 22 and 23) criticize the cost assumptions used for various resources. Do you have any comment?

A. Company Witness Mitchell discusses the cost assumptions for potential Company-owned resources, but I want to comment briefly on the price assumptions used for solar PPAs.

As with prior Plans, the Company used a market index price for solar PPAs based on the results of recent requests for proposals ("RFPs"). My Rebuttal Figure 3 shows the market index price used in this and prior Plans. As can be seen, while the Company has seen cost declines in the past, bids are beginning to flatten, and even increase slightly.

Rebuttal Figure 3: Solar PPA Prices



In the 2020 Plan, the Company looked to the bids received in response to its 2018 RFP for new solar and wind resources. In addition to slight price increases compared to the 2017 RFP for new solar and wind resources, four of the five conforming PPA projects with the lowest price in the 2018 RFP experienced significant issues and were withdrawn from consideration.

As the Company pursues a significant volume of solar PPAs going forward as required by the VCEA, the Company expects that PPA prices may increase further as the Company moves up the supply curve, absent any breakthroughs in solar or onshore wind technology. For example, if the Company had calculated the market index price with all

828 MW of conforming PPAs received in the 2018 RFP for new solar and wind resources, the PPA average price would have increased by $3.85 per MWh, or 11%.

Q. Staff Witness Abbott lists on page 17 of his testimony three issues regarding the Company's treatment of energy storage resources in PLEXOS. The first issue is "the Company's reduction of the nameplate capacity storage resources" in PLEXOS. Please respond.

A. I believe Mr. Abbott is mixing the concepts of energy output and capacity value. The Company does not reduce or de-rate the nameplate capacity of storage for energy dispatch—the energy storage resources were available for dispatch up to their full nameplate capacity in PLEXOS.

The "60% reduction" Mr. Abbott discusses is related to capacity value, which reflects the capacity revenue energy storage resources will receive. For the capacity value of storage in the 2020 Plan, the Company followed PJM's current rule, which dictates that for capacity market participation, a storage resource with duration less than 10 hours will be de-rated down to the capacity value equal to the resource's duration as a fraction of 10 hours. Stated another way, PJM allows (and the Company assumed) a 4-hour duration storage resource to receive a capacity value up to 40% of its nameplate rating. To qualify for this capacity value, the resource should be able to provide its full nameplate capacity output for the 4-hour duration, which is consistent with how the Company modeled storage resources in PLEXOS. I should note that PJM does have an ongoing stakeholder process to reevaluate the capacity value of storage resources; any ensuing updates resulting from this process will be incorporated into future Plans and Update Filings.

However, the 40% capacity value was the PJM rule as of May 1, 2020, when we filed the 2020 Plan and still remains so today.

Q. There seems to be some confusion with regards to energy storage capacity value and related concepts. Do you have any comments?

A. Yes, I would like to describe some of these concepts to help alleviate this confusion, including the concepts of capacity value, capacity bid value, capacity interconnection rights ("CIR"), capacity factor, and reliability contribution of a resource. The capacity value of a resource is its economic value in the PJM capacity market, whereas capacity bid value is the value the Company bids the resource into PJM capacity auction. The capacity value of a resource can differ from capacity bid value if there are significant performance risks for a resource, such as for a solar or wind resource. Capacity bid value for energy storage resources is currently capped by PJM's 10-hour rule. CIR can be defined as the right to input generation into the transmission system at the point of interconnection. CIR sets the cap for the capacity bid value of a resource. For energy storage resources CIR eligibility, PJM currently follows its 10-hour rule. The capacity factor of a resource is the average output divided by the nameplate capacity of a resource for a period of time. Think of capacity factor as a utilization metric. Base load units like nuclear have a high capacity factor, while peaker units like CTs have a low capacity factor. Finally, reliability contribution of a resource is typically a concept used for limited duration and intermittent resources, and is the reliability benefit the resource provides compared to a 100% available dispatchable resource.

These and other related capacity concepts around renewables, storage, and other intermittent resources make clear dialogue and debate more challenging, so it is important that these concepts and their distinctions are clarified and understood.

Q. The second issue is that the energy price forecast does not reflect the VCEA. Do you have any comment?

A. I agree that the commodity forecasts from ICF do not reflect the VCEA as noted in the 2020 Plan; the Company will update its commodity forecasts for future Plans and Update Filings, as reflected in my Rebuttal Schedule 1. Company Witness Scheller discusses her concerns with the energy price forecast presented by Staff Witness Johnson on which Mr. Abbott relies.

Q. The third issue raised by Staff Witness Abbott related to energy storage is the Company's use of unrealistic values for BESS in PLEXOS model that are not consistent with the green sheets data, highlighting the variable costs and maintenance rate inputs. Please comment.

A. Mr. Abbott is correct that the green sheet included a variable cost of $0.30 per MWh for BESS. Upon further research, the Company determined that the PLEXOS model did in fact include the $0.30 per MWh variable cost adder; that portion of the Company's response to Staff Set 18-172 was an inadvertent error.

As to maintenance rate, Mr. Abbott shows on the table on page 26 of his pre-filed testimony that the green sheet included a maintenance rate 14.1%. I believe he inadvertently calculated the 14.1% using a data point focused on maintenance man hours per year as part of annual O&M cost calculation. This data point should not be used to

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calculate availability. For BESS, expected outage rates are close to 0% given that most maintenance can be done during off-peak hours. In addition, only small sections of the entire BESS bank would be taken offline at any given time for planned or unplanned maintenance. Accordingly, the outage rate for BESS should be 1% or less. The Company does, however, agree that a 0% outage rating is an aggressive assumption and will reassess this outage rating assumption in the future Plans and Update Filings.

Q. APV Witness Rábago criticizes the Company on page 12 for not evaluating solar plus storage. Please comment.

A. The Company did not evaluate solar plus storage in the busbar or in PLEXOS because solar plus storage is still an evolving technology. As described in Section 9.2.2, the Commission has approved a pilot project for the Company to study solar plus storage, including the true benefit of these resources in combination rather than separate. The Company will evaluate solar plus storage in future Plans and Update Filings as this technology develops.

Q. On page 10 of his testimony, APV Witness Rábago states that the Plan "does not include any meaningful evaluation of combined heat and power resources or waste heat to power resources." Please comment.

A. Combined heat and power ("CHP") is the use of a power station to generate electricity and useful thermal energy from a single fuel source. Waste heat to power ("WHP") is a type of CHP that captures heat byproduct discarded by existing industrial processes and uses that heat to generate power. The costs of this type of resource are based on the details of a specific project. To develop such projects, the Company would need to find a host company that requires steam in its process or has extra steam that could be converted

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to power. While the Company has explored CHP and WHP opportunities, it has not yet identified any viable projects in Virginia.[2] The Company will continue to explore site availability.

Q. APV Witness Rábago criticizes the Company on page 11 of his pre-filed testimony for including nuclear license extensions for Surry and North Anna, while not "address[ing] the fact that nuclear generation has some of the highest busbar costs of any resource considered in the Plan." Why did the Company include the nuclear license extensions in all Alternative Plans?

A. The busbar cost that Mr. Rábago is pointing to is for new nuclear units. Extending the licenses for existing nuclear units is much less costly because the units are already permitted and operating. The Company did an economic analysis for the nuclear license extensions, which showed that these extensions were beneficial to customers.

The Company also included these extensions because nuclear in general is extremely important in a low- or no-carbon portfolio, providing around-the-clock base load generation, carbon-free energy, and grid stability. Obtaining the nuclear license extensions for Surry and North Anna will allow the stations to continue to provide approximately 28 GWh of carbon-free generation each year. This carbon-free generation is critical to serving customers while meeting the public policy objectives of the VCEA.

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[2] The Company notes that Figure 5.5.1 on page 88 of the 2020 Plan contains an error; CHP was not evaluated as a busbar resource or as an option in PLEXOS. The Company will correct this error at the evidentiary hearing.

V. "LEAST COST" PLANS

Q. The term "least cost" is used throughout the testimony of Staff and respondents, such as "least-cost Plan A" and "least-cost VCEA-compliant plan" discussed by Staff Witness Dalton (pages 9, 55), and "least-cost baseline" discussed by NRDC Witness Levin (page 38) and APV Witness Rábago (page 9). What is your understanding of statutory or Commission requirements regarding "least cost" planning and plans?

A. My understanding of the statutes related to integrated resource planning in Virginia highlight multiple factors to be considered. Va. Code § 56-597, for example, defines an integrated resource plan as "a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years *to promote reasonable prices, reliable service, energy independence, and environmental responsibility.*" I read that to mean that a Plan should take a holistic approach to resource planning. For example, a Plan should not ignore reasonable prices to promote environmental responsibility, nor should a Plan ignore reliability to promote reasonable prices. As with prior Plans, the Company developed the 2020 Plan with these tenets in mind.

Separate from the statute, the Commission has ordered the Company to include what it calls a "true least-cost plan." Based on prior Commission orders, the Company understands this requirement to mean that the "true least-cost plan" should not "force the modeling to select any resource, nor exclude any reasonable resource," and should not include legislative requirements or corporate goals. According to the Commission, this provides a benchmark against which to measure the cost of other alternative plans.

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Q. Looking first at the 2020 Plan itself, Staff Witness Dalton and Consumer Counsel Witness Norwood seem to state that the Company did not present a "true least-cost plan" as required by prior Commission orders. Staff Witness Dalton bases his opinion on the 480 MW annual limit on solar resources and the inclusion of VCHEC and the Biomass Units in Alternative Plan A (page 55), while Consumer Counsel Witness Norwood bases his opinion on the 480 MW annual limit on solar resources and other build constraints placed in PLEXOS (page 16). Please comment.

A. I have discussed why the results of the financial analysis do not necessarily mean that it is economic to retire VCHEC and the Biomass Units. Company Witness Mitchell explains the rationale for the commonsense build constraints placed in PLEXOS. I would also note that the Company has incorporated similar build constraints for all resources in prior Plans and that, to my knowledge, except for the annual limit on solar resources, neither Staff nor respondents have challenged the reasonableness of these assumptions, including for the least-cost plan. The Company does not believe that the Commission directive to not "exclude any reasonable resource" precludes the Company from placing constraints in PLEXOS to ensure that the resulting plans are feasible.

As to the 480 MW annual limit on solar resources, Staff Witness Dalton supports his position on pages 30 and 31 of his pre-filed testimony by referring to the bids received in response to prior RFPs. Specifically, he highlights that the Company received bids for approximately 3,180 MW of solar resources in its 2018 RFP for new solar and wind resources. What Mr. Dalton does not mention is that a portion of the bids received did not conform to the specifications required by the RFP. In fact, only 15 of the PPA proposals received totaling 828 MW conformed to the RFP requirements. Further, as I

mentioned above, of the 148 MW of PPA proposals the Company tried to execute, 128 MW (*i.e.*, four of five proposals) were withdrawn from consideration based on significant issues experienced by the project developers. Based on these results, I believe it is clear that the focus should be on projects successfully developed, not just bids received. Company Witness Mitchell provides further information on the projects successfully developed in Virginia in recent years and comments on the 480 MW annual limit. That said, the Company does not oppose increasing this annual limit in future Plans and Update Filings based on the development envisioned by the VCEA.

Q. Staff Witness Dalton criticizes the Company for not developing a "least-cost VCEA-compliant plan," and recommends on page 56 of his testimony that the Commission direct the Company to do so in future Plans. Do you have any comment?

A. I do. The testimony in this proceeding makes clear that there is no consensus on what a "least-cost VCEA-compliant plan" would entail, or even what "VCEA-compliant" means. For example, NRDC Witness Levin disputes what the VCEA "requires" in terms of carbon regulations, as discussed above. APV Witness Rábago (page 12) seems to state that the VCEA requires 1,100 MW of small-scale solar, but that the other 15,000 MW of utility-scale solar mentioned in the same subsection of the VCEA is not required. Staff and NRDC seem to say that some offshore wind is required by the VCEA, but not 5.2 GW. Staff also seems to imply that 2.6 GW of offshore wind would be included in a "least-cost VCEA-compliant plan," but that an additional 2.6 GW would not. In addition, Staff states that a "least-cost VCEA-compliant plan" would include an early retirement of VCHEC, despite the fact that the VCEA acknowledges the possibility of VCHEC operating through 2045. As another example, Staff and respondents question Alternative

Plans B and B_{19} for preserving natural gas-fired generation, where the VCEA allows the Company to continue to run such units beyond 2045, if it petitions and the Commission finds that threats to reliability or security exist. In sum, many of the provisions of the VCEA require interpretation. For these reasons, the Company opposes the blanket recommendation that the Commission require a "least-cost VCEA-compliant plan."

Q. What does the Company suggest?

A. I generally agree that it is helpful to have a benchmark or a baseline against which to evaluate other alternatives. I agree with NRDC Witness Levin and APV Witness Rábago, however, that the current Commission requirements for a "true least-cost plan" as embodied in Alternative Plan A is outdated, as Plan A is not only unrealistic, but now contrary to Virginia joining RGGI and the mandatory RPS Program. It seems an unnecessary use of resources for the Company to continue to pay ICF to produce a commodity forecast that assumes no carbon regulations in Virginia when Virginia now has carbon regulations.

The Company suggests that the Commission maintain a requirement for future Plans to include a least-cost plan to use as a benchmark but clarify that this plan should model (i) applicable carbon regulations and (ii) the mandatory RPS Program. The Commission should maintain that the least-cost plan not force the model to select any specific resource nor exclude any reasonable resource. However, the Commission should clarify that the Company may include in this least-cost plan commonsense build constraints, such as a reasonable limits on the maximum number of specific resources that could feasibly be built in one year and a set year a resource is available as an option based on realistic permitting and construction timelines for the specific resource. Company Witness

Mitchell explains the rationale for such commonsense build constraints. Other than these requirements, the Company should allow its model to optimize the accompanying resource plan.

This revised least-cost plan would satisfy the strict requirements of the VCEA and related legislation (*i.e.*, carbon regulation, RPS Program), but would avoid unnecessary litigation on the exact contours of the law as it relates to specific resources and what is or is not "VCEA compliant." Further, with the Company agreeing to allow PLEXOS to determine the timing of unit retirements, this should alleviate disagreement on that issue. This revised least-cost plan would also provide the Commission with a reasonable baseline against which to evaluate alternatives.

VI. RELIABILITY

Q. You have noted throughout your testimony the importance of reliability. How does PLEXOS account for reliability?

A. The PLEXOS model accounts for reliability both through annual capacity reserves using a reserve margin, as well as a simulated hourly dispatch that takes into account system load, energy efficiency, demand response, unit outages, and must-take resources like wind and solar. At the core of the model's optimization is the requirement to serve load and prevent unserved energy in any given hour. From there, the model will consider annual reserve margins to make sure there is sufficient capacity to meet the PJM capacity requirements. After that, the model simulates unit dispatch and verifies that there are sufficient resources to serve hourly load with both dispatchable, non-dispatchable, and transactional resources like PJM market purchases. The Company believes above all that system reliability is a necessity and the PLEXOS model's internal processes follow a

similar objective. Nevertheless, PLEXOS does not evaluate all potential reliability issues, as discussed further by Company Witness Kyle Thomas.

Q. Staff and respondents provide testimony on both the 970 MW of CTs added as a placeholder to address reliability concerns, and the 9,500 MW of natural gas-fired generation preserved in 2045. Please respond.

A. Company Witness Kyle Thomas discusses reliability from a transmission perspective, but there are also reliability concerns from a generation perspective. The Company must serve its customer reliably throughout the year and in all types of weather conditions. I am hopeful—as most folks that try to plan for a carbon-free future are—that some new, cost effective, long-lasting, carbon-free dispatchable resource will be developed within the next 15 years. That said, the Company *must* provide reliable service to its customers. Based on current technology, preserving low emission, dispatchable natural gas generation is an option, as shown in Alternative Plans B and B_{19}. I would also note that the Company is not alone in its consideration of this option, with NRDC Witness Levin presenting modeling that leaves natural gas generation online.

Section 5.6 of the 2020 Plan discusses some of the challenges related to the addition of significant volumes of solar generation, including challenges related to capacity, energy, and the solar production profile.

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Q. Focusing first on capacity, Consumer Counsel Witness Norwood highlights the excess capacity in the Company's Alternative Plans on pages 19 to 20 of his pre-filed testimony, and recommends that the Commission direct the Company "to evaluate alternatives to mitigate excess capacity." Similarly, Staff Witness Dalton comments on excess capacity and energy on pages 33 and 34 of his testimony. Please explain why each Alternative Plan has excess capacity and energy, and comment on Mr. Norwood's recommendation.

A. The data presented by Witness Norwood in Table 3 (page 19) focuses on firm capacity in the summer. Figure 5.6.1.1 on page 97 of the 2020 Plan shows a comparison of firm capacity in the summer and winter, as well as the nameplate capacity. As can be seen, while the Company likely will have excess capacity in the summer because of the value of solar resources in meeting the summer peak, the Company may be capacity deficit in the winter. While the Company must satisfy its PJM capacity obligations, the Company must also have confidence that it can keep the lights (and, for some, heat) on in the winter.

Q. Do these seasonal differences also affect energy?

A. Yes. With the significant development of solar resources, the Company would likely need to import a significant amount of energy during the winter but would need to export significant amounts of energy during the spring and fall. This calls into question one of the statutory tenets of integrated resource planning—energy independence—and increases risks to reliability to the extent neighboring states also implement similar changes to their generation portfolios.

Q. Are there other possible effects on reliability with significant development of solar resources?

A. Yes. In the spring and fall, solar can produce more energy than is needed to meet customer demand during the daytime, a profile commonly referred to as the "duck curve," which is illustrated in Figure 5.6.3.1 of the 2020 Plan. For example, in 2045 as the sun sets in the evening and folks are home cooking and turning on their TVs, the system may have to ramp from negative 20,000 MW to consuming over 11,000 MW over a three-hour period. That change of 31,000 MW in a three-hour period is five times more than the Company currently experiences. This possibility emphasizes the need for dispatchable generation—units that can be turned off and on as needed and follow customer load requirements.

This possibility also emphasizes the need for solutions to mitigate wasted excess energy. As the Company deploys more solar resources on its system, it may become more economic at certain times of day to curtail production from certain solar facilities when compared to the costs of building additional energy storage resources, increasing transmission export capacity, or facing negative energy prices. Curtailing production from solar facilities will not only lower the value of these facilities, but will also decrease the amount of RECs that those facilities produce for RPS Program compliance.

Q. Consumer Counsel Witness Norwood testifies on page 20 that it is plausible that future load growth or PJM market prices for capacity and energy could be lower than forecasted. Do you agree?

A. I agree that it's possible. But I would also note that it is equally plausible that PJM increases its reserve margin to cover abnormal weather conditions and winter peaks as

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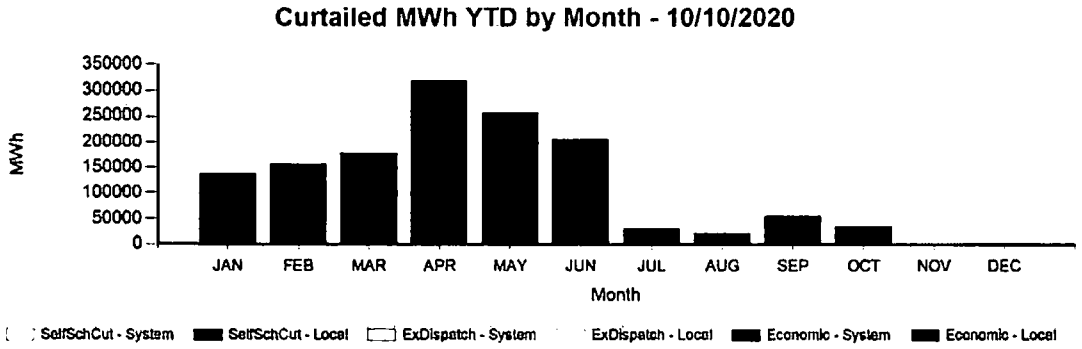
additional intermittent renewable energy generation comes online and as more jurisdictions within PJM push toward non-dispatchable, carbon-free resources.

Q. You mentioned California earlier in your testimony. Please briefly expand on this example.

A. Yes. California's RPS program currently requires that 60% of retail sales be served by renewable resources by 2030. Accordingly to the California Independent System Operation ("CAISO"), approximately 27% of CAISO load in 2019 was served by renewable energy.[3] With these increasing levels of renewable resources, California has seen significant curtailments of renewable energy. My Rebuttal Figure 4 shows curtailed MWh by month through October 10, 2020, as reported by CAISO.

Rebuttal Figure 4: Wind and Solar Curtailments in California[4]



Based in part on this resource mix, California has been in the news recently. California

[3] California ISO, *Monthly Renewables Performance Report – Dec. 2019, available at* www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Dec.2019.html.
[4] California ISO, *Wind and Solar Curtailment October 10, 2020, available at* http://www.caiso.com/Documents/Wind_SolarReal-TimeDispatchCurtailmentReportOct10_2020.pdf.

experienced rolling blackouts in August of this year and narrowly avoided blackouts again just two weeks later over Labor Day weekend. According to Platts Megawatt Daily from August 18, 2020, the California power system experienced shortages of 3.8 to 4.4 GW during the blackouts as record heat drove demand that could not be met by lower-than-expected renewable energy generation. The highest loads were experienced between 5 pm and 8 pm (PST) when solar generation was declining with the sunset. It was also during this time that the state lost 1.0 to 1.8 GW of wind power. In summary, California had record heat and high demand just as the sun was setting and the wind died down.

Q. Does the Company oppose the development of significant solar resources?

A. No, not at all. The Company is committed to a cleaner energy future. My only point in raising this issue is that a path must be found to achieve this future without compromising reliability of electric service. As discussed above, this will likely require technological advancements in the future.

VII. MODELING BY SIERRA CLUB AND NRDC

Q. Sierra Club and NRDC both presented the results of separate modeling efforts. Do you have any initial comments on these results?

A. Yes. I will comment on each modeling effort separately but want to note at the outset some of the similarities between the results of these modeling efforts and the alternative plans presented by the Company. Like all Alternative Plans presented by the Company, the modeling presented by Sierra Club and NRDC show the development of significant amounts of solar, wind, and energy storage resources, and include the nuclear license extensions. Further, like Alternative Plans B and B_{19}, the modeling by Sierra Club

Witness Wilson and NRDC Witness Levin do not retire Virginia natural gas units. I believe this highlights the importance of dispatchable generation to system reliability. The primary differences were associated with the timing of resource additions and unit retirements. These are not insurmountable differences, and all of us can work towards the best solution for customers and the Commonwealth.

Q. Okay, let's start with your comments on the modeling efforts of NRDC Witness Levin. Please comment.

A. Generally, as Witness Levin acknowledges, the NRDC analyzed all of Virginia rather than the Company's service territory. Therefore, the results and conclusions cannot provide an apples-to-apples comparison to the 2020 Plan. The modeling presented by NRDC also does not appear to meet the interim targets for the development of solar resources as outlined in the VCEA.

Ms. Levin added a carbon price of $200 per ton in 2045 and beyond. Through discovery (DEV to NRDC Set 2-12), she explained that this represents the cost of removing CO_2 using direct air capture. This response is included in my Rebuttal Schedule 2. While I disagree that this price is necessarily a conservative assumption, Ms. Levin seems to recognize the option of pursuing net zero carbon rather than zero carbon. This option also acknowledges the importance of dispatchable generation. Witness Levin also included an onshore wind resource in her modeling, but acknowledged the data was not necessarily sourced from a site located in Virginia.

Q. Do you have any final comment on the modeling completed by NRDC Witness Levin?

A. Yes, I would just note that Ms. Levin criticized the Company for not using an annual CO_2 emission limit in PLEXOS as discussed above, but she did not do so in her optimization modeling either, as discussed on page 31 of her testimony.

Q. Turning to the modeling performed by Sierra Club Witness Wilson. Please comment.

A. As I noted above, the results of the "Synapse Optimization" scenario presented by Sierra Club are similar to those produced by the Company. In addition, Witness Wilson smartly focused on the 15-year planning period. The Synapse Optimization scenario builds less solar resources overall never getting to the 16,100 MW of new solar or onshore wind resources in 2035 as envisioned by the VCEA. The scenario also builds solar at a faster pace (though Ms. Wilson acknowledges on page 24 of her testimony that the amount of solar built in 2021 is likely not feasible). Energy storage deployment is delayed through 2033, and then built rapidly.

On page 25 of her testimony, Ms. Wilson identifies the largest fuel mix difference between the Synapse Optimization scenario and the "Dominion Preferred" scenario as net imports. I would note that this means that the Synapse Optimization scenario relies more heavily on outside markets for reliability, and thus has potentially higher CO_2 leakage (*i.e.*, imported emissions).

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VIII. FORWARD CAPACITY MARKETS

Q. In his testimony, Sierra Club Witness Frost explains PJM's Minimum Offer Price Rule ("MOPR") and the fixed resource requirement ("FRR") alternative in PJM, as well as the implications of MOPR on the Company's operations and the possible benefits of the FRR alternative. Do you have any comment?

A. Sierra Club Witness Frost details the specifics of the MOPR and the FRR alternative fairly accurately. Under the MOPR order issued by the Federal Energy Regulatory Commission ("FERC"), there is a risk that many of the new renewable resources required by the VCEA will be subject to MOPR and therefore may be unlikely to clear the market. This could result in customers "paying twice" for capacity—once to procure the new resources and again in the PJM capacity market.

Under the FRR alternative, these new renewable resources can still be included to meet the Company's capacity obligation. Therefore, I agree with Mr. Frost that the FRR alternative likely provides customer benefits over the long-term. However, the Company is awaiting additional data, including FERC's final acceptance of PJM's MOPR compliance filing, the capacity auction timelines, and PJM's updated 2021 load forecast (which will determine the Company's FRR load obligation) before making a final determination on whether or when to elect FRR.

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1 **Q. Sierra Club Witness Frost states on page 11 of his testimony that the Company**
2 **should have performed a comprehensive analysis of the benefits and costs of the**
3 **FRR alternative and the impacts of MOPR as part of this 2020 Plan. Similarly,**
4 **Staff Witness White notes on page 6 of his testimony that the Company did not**
5 **provide an analysis of the effects of MOPR. Why did the Company not present such**
6 **analyses in the 2020 Plan?**
7 A. FERC has not yet issued a final ruling on PJM's filings related to MOPR, and it remains
8 to be seen how a final ruling will impact MOPR and the FRR alternative. The timing of
9 the next capacity auctions and any updates to the PJM load forecast in 2021 will also
10 affect any final analysis and ensuing FRR decisions. Until these are finalized, the
11 Company does not believe it has the information necessary to complete a comprehensive
12 analysis.

13 **Q. On page 18 of his testimony, Sierra Club Witness Frost recommends that the**
14 **Commission require the Company to conduct a full cost-benefit analysis of the FRR**
15 **alternative relative to continued participation in the PJM capacity market and to**
16 **address whether the Company's solar resources will be able to clear the Reliability**
17 **Pricing Model ("RPM") under MOPR. Please comment.**
18 A. The Company understands PJM rules, its load obligations, and generation characteristics;
19 bidding and optimizing our units into the PJM energy, capacity, and ancillary markets are
20 the types of operational decisions the Company makes on a routine basis and is well
21 equipped to do. The Company will certainly complete a comprehensive analysis once the
22 rules are finalized. This is the type of operational analysis the Company performs in the
23 usual course of business as a PJM market participant. The Commission need not make an

additional requirement as part of integrated resource plan proceedings. This in-depth analysis will include costs, benefits, and risk assessment of the available alternatives, comparing the FRR alternative to the RPM construct.

Q. Sierra Club Witness Frost also recommends on page 18 that the Commission open a docket specifically to address the Company's FRR and MOPR analysis. Do you have any comment?

A. The Company opposes this recommendation. As stated above, the election of FRR is more of an operational question of how the Company will optimize its portfolio in the capacity market. A separate FRR docket is not needed, nor is it practical given the timelines required to make an FRR decision. It is unlikely that there will be sufficient time for a docket to be opened, litigated, and resolved between when FERC issues its final ruling, when PJM load forecasts are updated, and when the Company must make a decision on whether to elect the FRR alternative, acquire potential capacity resources, and submit an FRR plan to PJM. The Company intends to keep Staff informed of its progress and any decisions related to FRR.

Q. Staff Witness White recommends that, should the Company elect the FRR alternative, the capacity price forecast be updated to incorporate the effects of the Company's election. Does the Company oppose this recommendation?

A. No, the Company does not generally oppose this recommendation, though it may depend on the timing of when an FRR election would need to happen compared to when the Company updates its commodity forecasts in its usual course of business.

Q. On page 14 of his pre-filed testimony, Staff Witness White includes a list of information that the Company should include in future filings related to the Company's capacity position. Please comment.

A. The Company does not oppose providing this information as a general matter, and already does provide much of this information in its Plans, such as the load forecast and each existing generation unit. The Company would suggest that the Commission adjust subpart (iv) of the recommendation to require only each *Company-owned* generation unit interconnected at the transmission level in PJM, as this is the information relevant to accomplishing the stated purpose of tracking the Company's generation portfolio. Otherwise, the Company does not oppose this recommendation.

IX. MISCELLANEOUS

Q. On page 32 of his pre-filed testimony, APV Witness Rábago lists as a "major deficiency" of the 2020 Plan that Alternate Plans C and D assume emissions leakage. Please comment.

A. "Leakage" in the emissions space generally refers to imported emissions. For example, because RGGI is not a national carbon reduction initiative, generators outside of the states participating in RGGI can sell "dirty" MWh into the RGGI region without any carbon cost. When you import or buy energy from PJM, you are essentially buying the marginal unit, which currently is a carbon-emitting generator. The 2019 PJM Emissions Report indicates that the marginal CO_2 emissions for the year were approximately 0.62 short tons per MWh.

Figures 2.2.5 and 2.2.6 on pages 30 and 31 of the 2020 Plan illustrate this issue. While Alternative Plans C and D retire all Company-owned carbon-emitting generation in 2045,

resulting in close to zero CO_2 emissions from the Company's fleet in 2045, these plans also require significantly more imports. As shown on Figure 2.2.6, all Alternative Plans have similar emissions in 2045 when considering leakage.

Emission leakage is a topic that is still being explored in the industry and will likely remain a topic of discussion going forward. For example, the generation fuel mix of electricity in the Northeast states has shifted dramatically over the past decade from 2006 to 2016. Due to increased access to low-cost natural gas from the Marcellus Shale, as well as environmental policies at the federal and regional level, coal-fired generation has significantly declined while natural gas generation has surged in the Northeast region.[5] At the same time, according to the most recent 2017 Monitoring Report issued by RGGI in November 2019, net imports into the nine-state RGGI region have increased by 39.6%[6] from the 2006 to 2008 base period to the 2015 to 2017 monitoring period. This can be characterized as leakage.

Neither RGGI nor PJM has developed a solution to curb CO_2 leakage between RGGI and non-RGGI states. PJM has assembled the Carbon Pricing Senior Task Force to explore carbon pricing mechanisms for its energy market with a goal to appropriately price carbon in order to reduce leakage.

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[5] U.S. Energy Information Administration, *Natural Gas Has Displaced Coal in the Northeast's Generation Mix Over the Past 10 Years* (May 11, 2017), *available at* https://www.eia.gov/todayinenergy/detail.php?id=31172.

[6] RGGI, CO_2 Emissions from Electricity Generation and Imports in the Regional Greenhouse Gas Initiative: 2017 Monitoring Report at 4 (Nov. 8, 2019), *available at* https://www.rggi.org/sites/default/files/Uploads/Electricity-Monitoring-Reports/2017_Elec_Monitoring_Report.pdf.

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1 **Q. Besa Witness Cusick (page 13 to 14) and APV Witness Rábago (pages 28 to 29)**
2 **comment on the capacity factors shown in the 2020 Plan for pumped storage, with**
3 **Mr. Rábago classifying the performance of the Bath County Facility as**
4 **"substandard." Please comment.**
5 A. Under current conditions, and for the foreseeable future, Bath County ("Bath"), like all
6 energy storage assets, is primarily a capacity resource rather than an energy resource.
7 Storage resources consume energy during inexpensive hours and generate energy in high-
8 priced hours. Storage resources provide financial benefits when the energy price
9 difference is greater than the round-trip efficiency loss. The round-trip efficiency for
10 Bath is approximately 80%. Bath is optimized by PJM in its day-ahead market and is
11 actively managed by the Company in real time and across days to maximize its value to
12 customers and grid reliability. As more renewable energy resources enter service, the
13 expected power peaks and valleys may flatten and change over time, making operating
14 Bath even more important as a reliability resource.

15 **X. CONCLUSION**

16 **Q. Mr. Kelly, do you have any final comments in response to the testimony of Staff and**
17 **respondents?**
18 A. Yes, only to briefly reiterate my initial comments. The Company is committed to a
19 cleaner energy future. Given the short timeframe between the Commission's March 9
20 Order and the May 1, 2020 statutory deadline to file the 2020 Plan, the Company had to
21 make several simplifying assumptions in order to model the VCEA. Even so, this 2020
22 Plan presents a reasonable first step at evaluating and planning for transformational
23 changes to the Company's system. The short-term action plan specifically identifies

reasonable near-term actions to support this transition. In future Plans and Update Filings, the Company will continue to work diligently to determine a path to clean energy that meets public policy objectives while maintaining the standard of reliability that customers expect and deserve at the lowest reasonable cost.

Q. Consumer Counsel Witness Norwood recommends that the Commission reject the 2020 Plan, while NRDC Witness Levin (page 39), Sierra Club Witness Wilson (page 35) and APV Witness Rábago (page 33) suggest that the Commission order the Company to re-run the 2020 Plan. Please respond.

A. The Company opposes these recommendations. The Company has presented a reasonable Plan within the timeframe allotted. In addition, the Company has agreed with many of the recommendations made by Staff and respondents and has committed to process improvements and additional analyses, as outlined in my Rebuttal Schedule 1. Accordingly, I believe that many of the issues will be addressed through these improvements and analyses in future proceedings. These improvements and analyses will now take time to implement. Requiring the Company to re-run the 2020 Plan will rush this process, may not be achievable in the statutory timeline for this proceeding, and may lead to additional criticism based on what the Company can or cannot complete. Instead, the Company asks the Commission to give guidance and direction for focus on future Plans and Update Filings, and to give the Company time to perform the necessary improvements and analyses to do so as well.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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Company Commitments for Future Plans and Update Filings

This schedule summarizes the commitments the Company will make for future integrated resource plans ("Plans") and associated update filings as appropriate, and indicates which witness sponsors each commitment. The timing for each commitment may vary based on the complexity of the refinement or analysis.

Refinements to PLEXOS (Kelly)

- Model RPS Program, including:
  - Determination of and optimization around the annual requirements based on parameters set forth in Va. Code § 56-585.5;
  - Banking RECs for up to five years, or monetizing excess RECs; and
  - Option to select a deficiency payment in place of a resource.
- Allow PLEXOS to determine timing of unit retirements

Updates to Modeling Assumptions for Future Plans and Update Filings

- Load forecast (R. Thomas)
- Commodity forecast (R. Thomas)
- New resource cost estimates (Mitchell)
- Solar integration costs (R. Thomas)

Modeling Sensitivities

- Fuel and energy prices (R. Thomas)
- Load forecast (R. Thomas)
- Energy efficiency savings (E. Hall)
- Capacity prices (R. Thomas)
- REC prices (R. Thomas)
- Solar capacity factor (if Company assumption differs from prior three-year average) (Mitchell)

Additional Reliability Analyses (K. Thomas)

- 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.

NRDC
CASE NO. PUR-2020-00035
VIRGINIA ELECTRIC AND POWER COMPANY
DEV Set 2

Question No. 2-5:

Refer Section 4.5 of the 2020 Plan and the Company's response to Staff Set 3-48, which describe how the Company modeled compliance with the RPS Program in the 2020 Plan. Also refer to page 8 of Witness Levin's pre-filed testimony, which states that the Company "did not model the VCEA's clear RPS requirements." Please reconcile these two statements. Provide specific facts, instances and supporting workpapers to support the statement that the Company did not model the "VCEA's clear RPS requirements."

Response 2-5:

It is not evident from the IRP and related Responses that the Company optimized its renewable build-out or compliance strategy to meet the annual RPS generation requirements in a least-cost manner, with Plans that potentially exceed (rather than simply meet at lowest possible cost) the VCEA's annual REC requirements. It is also not evident whether the Company allowed for potential REC sales, in the event excess RECs were generated by Company assets.

Respondent:
Amanda Levin
Senior Policy Analyst
NRDC

NRDC
CASE NO. PUR-2020-00035
VIRGINIA ELECTRIC AND POWER COMPANY
DEV Set 2

Question No. 2-12:

Refer to page 29 of Witness Levin's pre-filed testimony, which states the assumption that "a $200 / ton (in 2017$) will be levied on all in-state fossil emissions in 2045 and beyond. Please explain how this amount was determined, and provide all associated workpapers.

Response 2-12:

This cost was designed to be a highly conservative estimate of a future technology that could be installed at the plant site to net out on-site emissions, or otherwise eliminate them. The value was chosen based on a review of potential forecasted costs for a variety of technologies, including direct air capture and hydrogen produced via electrolysis, though the model does not build or chose among these technologies: the $200/ton value is a proxy for future, commercial technology.

Cost estimates studied to determine a conservative estimate are: Keith, D (2018), "A Process for Capturing CO2 from the Atmosphere" (estimating that the levelized costs of Direct Air Capture would range from $94 to $232 per ton CO_2 from the atmosphere, available at www.sciencedirect.com/science/article/pii/S2542435118302253); and BloombergNEF's Hydrogen Economy Outlook, (2020), (projecting that the marginal abatement cost of using hydrogen in gas power generation could be $110/ton by 2050, available at https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf).

Respondent:
Amanda Levin
Senior Policy Analyst
NRDC

NRDC
CASE NO. PUR-2020-00035
VIRGINIA ELECTRIC AND POWER COMPANY
DEV Set 2

Question No. 2-26:

Refer to Exhibit AL-3.

a. **Please provide the NPV of the total system cost for the scenario "NRDC20 BAU"**

All cost outputs, including system costs, are provided in NRDC Response to DEV Set 1-3, "Attachment DEV Set 1-3 IPM Full (AL) CONF."

NRDC did not tabulate a NPV for total system costs.

b. **Only seven years are shown in Exhibit AL-3. Please provide all years in a digital format with all equations intact. If only seven years of information exists, explain why all years through 2045 were not modeled?**

Please reference footnote 48 on page 28 of the Direct Testimony of Amanda Levin.

IPM uses run years. As discussed in EPA's documentation at 2-6: "Another important structural feature of IPM is the use of model 'run years' to represent the full planning horizon being modeled. Although IPM can represent an individual year in an analysis time horizon, mapping each year in the planning horizon into a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. IPM takes into account the costs in all years in the planning horizon while reporting results only for model run years."

Thus, the model does model every year between 2020 and 2054, but these are averaged into seven model run years. The Run Year and Analysis Year Mapping Used are:

Run Year	Years Represented
2020	2020
2022	2021 - 2022
2025	2023 - 2027
2030	2028 - 2032
2035	2033 - 2037
2040	2038 - 2045

2050	2046 - 2054

c. Please explain the delta of 0.8 GW between "Capacity-Hydro" in 2025 (3.47 GW) and in 2030 (4.27 GW).

ICF's baseline IPM assumption included an 800 MW pumped storage build in 2030.

d. For each of the battery storage units used in the model

i. What was the size and discharge time at full capacity?
ii. What was the useful life?
iii. Was a decommissioning cost included in the modeling?
iv. What was the unit efficiency?
v. What was the installation capital cost (all inclusive)?
vi. What was the annual O&M and capital expenditures?

For questions i-vi, all battery and cost assumptions are derived from NREL 2020 ATB; see NRDC Response to DEV Set 1-3 "Attachment DEV Set 1-3 IPM Assumptions (AL)."

Specific to question ii, battery life was assumed to be 20 years, with a rebuild cost at 10 years. Specifically, overnight Capital Costs reported reflect all-in costs (including rebuild costs) levelized over 20 years. Rebuild costs reflect energy cost component ten years from online year. Energy costs assumed at 81% of total costs based on CA IRP ratios used to develop this methodology.

e. What is the forecasted capacity factor of new solar, existing pumped storage, new pumped storage, and new battery storage?

For capacity factor outputs for all technologies, please reference Amanda Levin Direct Testimony, Exhibit AL – 3.

f. What is meant by capacity factor for energy efficiency of 1.00?

This is a modeling construct. The capacity is sized to result in the specified generation assuming a 100% capacity factor.

g. Was the Bath County Pump Storage including in the NRDC modeling? If yes, what "Type" is pumped storage listed under?

Yes, listed under "hydro."

h. Please explain the line "Firm Price, All-Hours" and how was it incorporated in the model?

"Firm Price, All-Hours" is an output of the IPM model.

The model endogenously determines the wholesale energy price and capacity price for each model region, and "Firm Price, All-Hours" is a $/MWh figure that represents the combined average cost (energy + capacity) per MWh.

i. What were the costs and parameters of all the energy efficiency? Was the energy efficiency allowed to expire or was automatically renewed at the same cost?

Costs were based on the below supply curve (with the total available savings – equal to estimated incremental savings under the VCEA and held constant at 2025 incremental savings levels, through the end of the modeling period – split into three cost tiers):

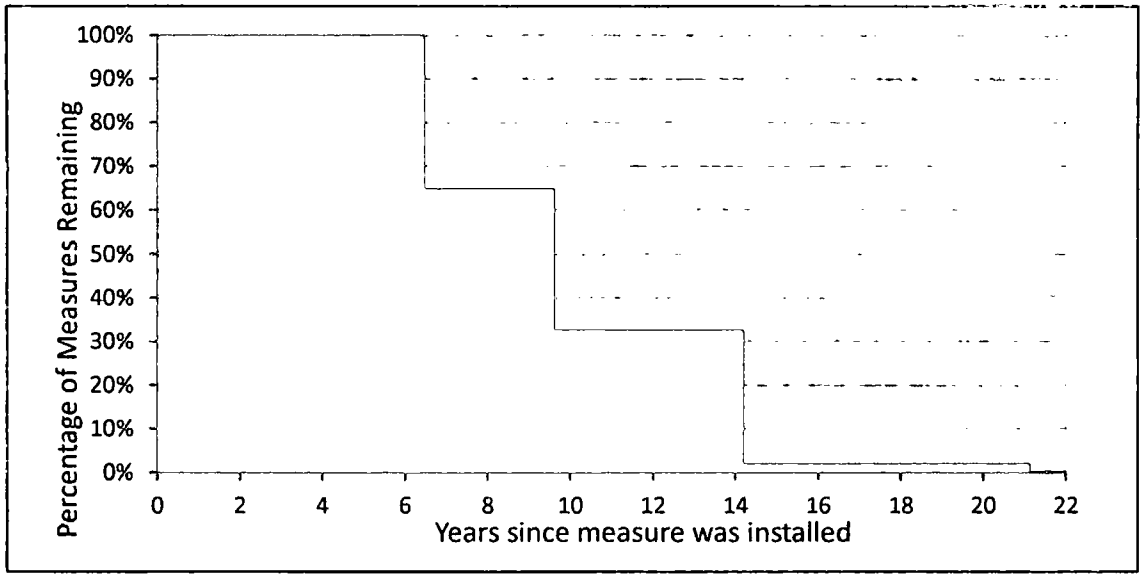
Levelized Cost of EE - All Years

TOTAL RESOURCE COST (Utility program and participant costs each account for 50% of Total Resource Cost)

cents/kWh	Low	Med	High
2017-2020	4.7	5.3	6.4
2020-2030	4.7	5.3	6.4
2030-2040	5.3	6.0	7.3
2040-2050	6.3	7.1	8.7

(Source: Hoffman, Ian M., et al. "The total cost of saving electricity through utility customer-funded energy efficiency programs: estimates at the national, state, sector and program level." *Berkeley Lab Technical Brief* (2015).)

Savings expired based on the four-tiered measure life used by LBNL (see below table). If economic, the model was allowed to procure incremental savings in each year after 2025 equal to the estimated savings achieved in 2025 under the VCEA.



The table above shows the numerical representation of the LBNL four-tiered measure life.

For each of the tiers, partial years are distributed in the current year and remaining percentages allocated in the next year.

(Source: "Energy savings, lifetimes, and persistence: Practices, issues, and data" (technical memo). LBNL, 2015.)

j. How was the RGGI price forecast developed?

The RGGI allowance price is endogenously determined by IPM. The model applies the regional carbon cap and determines the cost of an allowance based on supply and demand in each year. NRDC's modeling of RGGI includes the banking rules and other energy state policies (such as an RPS); it does not include the emissions cost reserve (ECR) or cost containment reserve (CCR).

k. Provide all unit parameters for all potential new assets considered in the model.

Please reference NRDC Response to DEV Set 1-3 "Attachment DEV Set 1-3 IPM Assumptions (AL)."

j. Provide all cost and operating assumptions for all existing fossil generation.

NRDC does not currently have access to these assumption inputs.

Nonetheless, please reference footnote 48 on page 28 of the Direct Testimony of Amanda Levin, specifically EPA's IPM Documentation Sections 4.1 and 4.2, discussing the National Electric Energy Data System (NEEDS), which is the source for data on all existing and planned-committed units in IPM.

Respondent:
Amanda Levin
Senior Policy Analyst
NRDC

Virginia Electric and Power Company
Case No. PUR-2020-00035
Virginia State Corporation Commission Staff
Staff Set 1

The following response to Question No. 19 of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on May 11, 2020, was prepared by or under the supervision of:

Peter Nedwick
Principal Engineer ET Planning & Strategic Initiatives
Dominion Energy Virginia

Question No. 19

Will the retirement of any of these coal units, either individually or taken cumulatively as a whole, create a system reliability issue that will require the construction of additional generation, transmission and/or distribution upgrades to address, similar to the transmission upgrades that were required for reliability purposes after Bremo was retired?

Response:

For the retirement of Chesterfield Units 5 & 6, the Company notified PJM of its intent to retire these units. As part of PJM's retirement analysis, PJM identified a reliability impact that would require a transmission solution to install a second 500–230 kV transformer at Chickahominy Substation at an estimated cost of $22 million. See Attachment Staff Set 01-19 (PN) for the slide from the April 2020 PJM TEAC meeting. The Company continues to evaluate additional impacts of the retirement of Chesterfield Units 5 & 6 on reliability and would expect additional projects (*e.g.*, transmission solution, generation solution, or some combination of transmission and generation solutions) to be needed. Those analyses are in progress.

For Mt. Storm, VCHEC, and Clover, no system reliability impact analyses related to the retirement of these units have been performed by the Company's transmission group.

Dominion Transmission Zone

Problem Statement: Generation Deliverability - Chesterfield 5 and 6

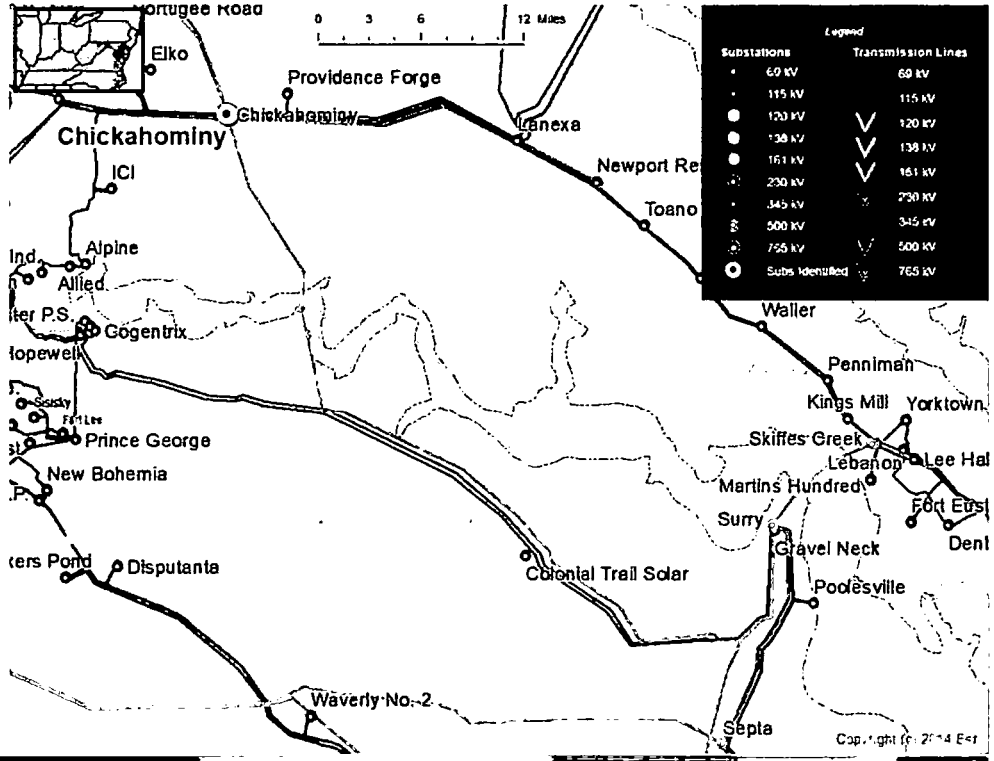
- Chickahominy 500/230 kV transformer is overloaded for loss of Chickahominy – Surry 500 kV line

Recommended Solution:

- Install the 2nd Chickahominy 500/230 kV transformer (b3213)

Required IS Date: 06/01/2023
Projected IS Date: 06/01/2023

Estimated Project Cost: $22M



Company Exhibit No. ___
Witness: GAK
Rebuttal Schedule 3
Page 2 of 4

2010-40003

Virginia Electric and Power Company
Case No. PUR-2020-00035
Virginia State Corporation Commission Staff
Staff Set 6

The following response to Question No. 79(a) of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on June 3, 2020, was prepared by or under the supervision of:

Peter Nedwick
Principal Engineer ET Planning & Strategic Initiatives
Dominion Energy Virginia

Question No. 79(a)

Please reference page 83 of the IRP that discusses generation retirements.

a. Describe in detail the processes and steps followed by the Company to identify and evaluate: (i) the transmission system reliability impacts potentially caused by generator retirements, and (ii) the transmission system upgrades required to mitigate such reliability issues.

Response:

As noted in the Company's response to Staff Set 1-20, the process to identify and evaluate the transmission reliability impacts to the Company's system potentially caused by generator retirements begins when a generation owner files a notice to retire a generating unit(s) with PJM. Upon PJM's receipt of this notice, a 90-day window starts the PJM retirements analysis process. In that process, PJM analyzes the retirement impacts associated with the projected retirement and provides its study results to the affected transmission owner(s) within 30 days of the receipt of the retirement notice. Each affected transmission owner will review PJM's results for accuracy and perform any additional reliability analyses that are required based on the transmission owner's criteria. If no transmission reliability impacts are identified by either PJM or the transmission owner(s), PJM will notify the generation owner that no reliability issues have been identified and that their retirement can proceed as planned. If reliability impacts are identified, then PJM will notify the generation owner that reliability impacts have been identified, which then triggers an additional 60-day window. Within this 60-day window, PJM and the affected transmission owner(s) determine the required improvements to resolve the identified reliability impacts. PJM will then present the proposed solutions to its stakeholders as part of its open and transparent planning process (*i.e.*, the PJM RTEP process). PJM will assign the identified reliability impacts to the appropriate transmission owner(s) as baseline projects. The generation owner is then notified that it can then proceed with their scheduled retirement as planned, if it so chooses, based on its consideration of all relevant

information. While the generation owner does not pay for transmission upgrades related to generating unit retirements, other considerations may arise for the generation owner to consider. For example, PJM offered to pay the Company as the generation owner of Yorktown Units 1 and 2 to keep the units running beyond the originally scheduled retirement date to ensure system reliability while PJM and the transmission owner worked through a long-term transmission solution.

200140003

WITNESS REBUTTAL TESTIMONY SUMMARY

Witness: Robert G. Thomas
Title: Director, Corporate Strategy

Company Witness Robert G. Thomas responds to the comments and recommendations of Staff and respondents concerning the Company's load forecasting process and solar integration costs.

Mr. Thomas notes that an integrated resource plan is a snapshot in time based on the circumstances that exist when the Plan is developed. In order to meet a May 1 submittal deadline, the Company must begin the development process in the fourth quarter of the preceding year. The Company was required by the Commission to utilize the PJM 2020 Load Forecast for this 2020 Plan; because PJM did not issue its 2020 Load Forecast until December 30, 2019, this initial stage of the process was hindered Even so, key inputs used in developing the 2020 Plan were finalized before COVID-19 was recognized as a pandemic, before the VCEA was signed into law, and before Virginia officially joined RGGI.

Mr. Thomas further explains that criticisms concerning the Company's load forecast serve no purpose because the Company used the 2020 PJM Load Forecast in accordance with Commission requirements. Further, Mr. Thomas points out that Appalachian Voices Witness J. Wilson's characterization and utilization of the "Itron alternative forecast" are incorrect.

In response to Staff Witness Johnson's preference for the artificial neural network ("ANN") technology employed by Enverus, Mr. Thomas notes that while ANN models are useful operationally in predicting short-term load, they reveal very little, if any, cause and effect relationships as to why load is or is not materializing, and their output is highly dependent on recent historical load events caused by weather and outages. In contrast, econometric forecasting utilized by the Company has more transparency.

In response to comments by Appalachian Voices Witness J. Wilson, Mr. Thomas explains that the Company revised its methods in this 2020 Plan to only use the monthly energy load ratio share for estimating its Zonal share of both peak and energy. This revision was incorporated because the energy data is a more stable metric relative to annual peak data, which, in the Company's view, provides greater accuracy since it is less likely to be skewed by outliers.

Mr. Thomas counters Appalachian Voices Witness J. Wilson's assertion that peak demand for customers other than data centers is decreasing as simply false. He additionally testifies that Mr. Wilson's forecast of flat to declining data center growth in as early as 2021 is not a likely outcome given the Company's near-term data center interconnection expectation. In summary, Mr. Thomas concludes that Itron developed a reasonable long-term forecast using a well-accepted modeling approach utilizing a long history of demand data that is consistent with expected near-term capacity additions and data center market data.

In response to Staff's concerns regarding limitations on the Company's analysis of solar interconnection and integration cost estimates, Mr. Thomas notes that the Company has and will continue to enhance its analysis and will include the results of these assessments in future Plans.

260400003

REBUTTAL TESTIMONY
OF
ROBERT G. THOMAS
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION
CASE NO. PUR-2020-00035

Q. Please state your name, business address, and position of employment.

A. My name is Robert G. Thomas, and I am Director – Corporate Strategy at Dominion Energy Services, Inc., testifying on behalf of Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"). My business address is 120 Tredegar Street, Richmond, Virginia 23219.

Q. Have you previously submitted testimony in this proceeding?

A. In lieu of pre-filed direct testimony, the Company submitted to the State Corporation Commission of Virginia (the "Commission") on June 1, 2020, a document that identified me as a witness who would appear and offer direct testimony at the evidentiary hearing in support of the Company's 2020 system-wide Integrated Resource Plan (the "2020 Plan"), specified those portions of the 2020 Plan that I adopt and sponsor, and attached a statement of my background and qualifications.

Q. Mr. Thomas, what is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to issues raised in testimony offered by Karl R. Rábago and James F. Wilson on behalf of Appalachian Voices ("APV"), Amanda Levin on behalf of the Natural Resources Defense Council ("NRDC"), Rachel Wilson on behalf of the Sierra Club, and Gregory L. Abbott, Bernadette Johnson, Earnest J. White, and Michael A. Cizenski on behalf of the Commission Staff ("Staff").

Specifically, I address recommendations and issues regarding the Company's load forecasting processes and development of solar integration costs in the Company's 2020 Plan.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony responds generally to the following topics raised by APV, NRDC, Sierra Club and Staff.

I. Load Forecasting

II. Data Center Forecasts

III. Solar Integration Costs

I. LOAD FORECASTING

Q. On pages 24-25 of his testimony, APV Witness Rábago asserts that the 2020 Plan is deficient in that it relies on out-of-date commodity forecasts that do not reflect COVID-19 impacts, passage of the Virginia Clean Economy Act ("VCEA") or Regional Greenhouse Gas Initiative ("RGGI") prices associated with the enactment of the VCEA. In addition, Mr. Rábago claims that the Company relied on a high-case federal CO_2 commodity forecast that unreasonably assumes that Virginia does not join RGGI. NRDC Witness Levin similarly asserts that the Company failed to include VCEA carbon limits in the carbon cost commodity forecast for Alternative Plans B-D (at 7-8). Please respond.

A. As the Commission has recognized, the Plan is a snapshot in time based on circumstances that exist when the Plan is developed. As such, inputs and technologies are evaluated every year. In order to meet a May 1 submittal deadline for a full integrated resource plan filing, the Company must begin the integrated resource planning ("IRP")

development process in the fourth quarter of the preceding year. The initial activities associated with that process are to procure the energy commodity forecasts and develop the load forecast. The Company was required by the Commission to utilize the PJM Interconnection, LLC ("PJM") 2020 Load Forecast for the Dominion Energy Zone ("DOM Zone") for this 2020 Plan; because PJM did not issue its 2020 Load Forecast until December 30, 2019, this initial stage of the process was hindered. Even so, these key inputs used in developing the 2020 Plan were locked down long before COVID-19 was recognized as a pandemic having impacts across the country and the Commonwealth, before the VCEA was signed into law, and before Virginia officially joined RGGI. Indeed, even Staff Witness Abbott acknowledges (at 2) that the Company's "failure to fully account for the effects of the [VCEA] ... is not surprising to some degree given that the VCEA was passed by the General Assembly in March 2020, and signed by the Governor in April 2020, and the Company was required to file its 2020 [Plan] by May 1, 2020." The Company will continue to evaluate inputs and technologies year over year—with proven technologies included as part of the expansion plan, and new technologies considered as they become commercially viable and help the Company meet the goals of the VCEA—and those results will be reflected in subsequent Plan filings.

Q. Sierra Club Witness R. Wilson (at 31-32) and APV Witness J. Wilson (at 4 and 8) also criticize the Company's load forecast, claiming that it does not consider the effects of the current COVID-19 pandemic. Please respond.

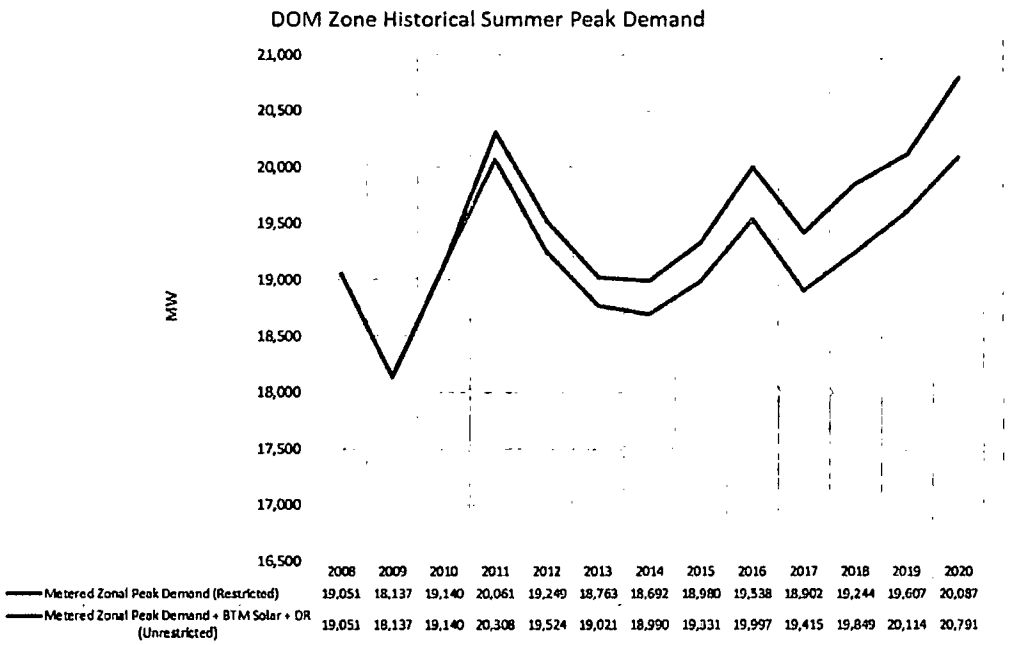
A. As mentioned above, the development of the 2020 Plan began in late 2019, with PJM's 2020 DOM Zone load forecast being an initial and key element in the development of the

Plan that was published by PJM on December 30, 2019. The COVID-19 virus was declared a pandemic by the World Health Organization in March 2020. Given the lateness of the pandemic declaration relative to the IRP development process schedule and given the magnitude of the that process, it was impossible to include the impact (if any) of COVID-19 on the DOM Zone load forecast and still meet a May 1, 2020 submittal date, for the 2020 Plan.

It should also be noted that despite the COVID-19 pandemic, the summer 2020 DOM Zone peak demand was the highest on record from both a restricted and unrestricted perspective. Restricted peak demand is simply the metered peak demand without adjusting for the impacts of behind-the-meter ("BTM") distributed energy resources ("DERs") and dispatched demand resources, while unrestricted peak demand adjusts the metered peak demand for the effect of these resources. The unrestricted peak demand figure is a measure of the real demand that exists in the DOM Zone, which, in the Company's view, is the proper measure to use in system planning exercises. Rebuttal Figure 1 below reflects the restricted and unrestricted annual summer peak demand for the period 2008 through 2020.

In addition to the above, when adjusting for customer choice losses and re-stating 2019 sales using a 15-year weather normalization method, the Company's 2020 year-to-date sales reflect a year-on-year growth rate of approximately 2.0%, which provides preliminary support that the overall COVID-19 sales impacts have been minimal to date.

Rebuttal Figure 1



Q. On pages 3-6 and 27-33 of his testimony, APV Witness J. Wilson acknowledges that the Company used the PJM Load Forecast for the 2020 Plan, as directed, but concludes that the forecast is unsupported and should be rejected due primarily to serious problems in PJM's new methodology. In contrast, Staff Witness Johnson asserts in the report attached to her testimony ("Report") that the Company's prior load forecasts have generally exhibited an upward bias despite actual results reflecting declining trends (Report at 5, 35-36), but finds that the PJM-derived load forecast appears to be more reasonable (Report at 5). Please respond.

A. In past Plan proceedings, I have been critical of PJM's load forecasting methods compared to those used by the Company. My position remains unchanged in that, in my view, the Company's load forecasting methods are preferable to those used by PJM. One of my principal criticisms has been that since 2015, PJM has been making major

revisions to its load forecasting process that have resulted in dramatic shifts in DOM Zone peak demand forecasts from year to year. This action alone creates instability in long-term planning, which results in dramatically different Plans from year to year. Since 2015, most of PJM's method revisions have caused their previous DOM Zone forecasts to dramatically decrease. PJM's revisions to its 2020 Load Forecast, however, caused a dramatic increase in its peak demand forecast for the DOM Zone relative to its 2019 Load Forecast.

Somewhat disingenuously now, APV Witness Wilson—who has in prior years supported PJM's forecast as superior to the Company's—is now a staunch critic of PJM's methods. For example, in the Company's 2017 Plan proceeding (Case No. PUR-2017-00051), Mr. Wilson stated on pages 3-4 of that testimony:

> I have compared the Company's current forecast, and its forecasting methodology, to those of PJM, and conclude that PJM produces a superior (if still conservative) forecast based on a superior methodology.
>
> ...
>
> PJM staff are continually evaluating and designing potential enhancements to their load forecasting methodology. They apply their methodology to forecast over twenty zones, and frequently evaluate the performance of their forecasts. In these efforts, PJM staff benefit from suggestions and reactions from approximately fifty load forecasters and other experts participating in the PJM Load Analysis Subcommittee, who represent the diverse regions of the PJM footprint.

Whereas APV Witness Wilson touted PJM's ability to develop a methodology to forecast over 20 zones in the 2017 Plan proceeding, he now suggests that PJM may be finding that it "difficult to find one approach that leads to reasonable forecasts in all zones" (Wilson at 28). Similarly, whereas Mr. Wilson previously characterized PJM's staff in 2017 as

"continually evaluating and designing potential enhancements" and "benefit[ing] from suggestions and reactions from approximately fifty load forecasters and other experts," he now believes PJM's staff is ignoring stakeholder feedback on PJM's new methodology (Wilson at 29) and generally acting without documentation or transparency (Wilson at 32). It appears Mr. Wilson felt a need in his 2020 Plan testimony to try to distance himself from his prior testimony regarding the PJM load forecasting methodology (*see, e.g.*, Wilson at 21). The reason for his sudden shift in support away from the PJM forecast to a lower forecast (which I discuss further below) this year is clear to me—Mr. Wilson merely advocates for a lower peak demand forecast regardless of its origin and underlying methodology.

Regardless, whether the Company, the Respondents, or the Staff support PJM's load forecasting methodology or not, the Company cannot defend PJM's forecasting methods. The Commission has ordered that the Company use the PJM Load Forecast for the DOM Zone in preparation of its 2020 Plan. The Company has done exactly that and will continue to do so until ordered otherwise.

Q. APV Witness J. Wilson also notes on pages 6 and 18-26 of his testimony that the 2019 Long-Term Electric and Demand Model Review ("Itron Model Review Study" or "Itron Study") prepared by Itron, Inc. ("Itron") included "alternative forecasts" that were generally lower than the Company's, and asserts that these Itron "alternative forecasts" are more accurate than either PJM's or the Company's. Is this a reasonable conclusion?

A. No, it is not. For purposes of this 2020 Plan, APV Witness Wilson's criticism of the Company's load forecast serves no purpose. The Company used the 2020 PJM Load

Forecast for the DOM Zone as the basis of all its Alternative Plans put forward in the 2020 Plan in accordance with Commission requirements.

That said, APV Witness Wilson constructs his own forecast based on the Itron Model Review Study to generate a lower forecast. The Itron Study was never intended to be a forecast for the DOM Zone or the Dominion Load Serving Entity ("DOM LSE"), but rather to review the current Company forecasting approach and to develop a set of recommendations for improving the underlying forecast models. Each of the underlying customer class sales models were evaluated independently. Itron never generated a total sales, energy, or peak demand forecast as part of the Itron Study. Rather, Mr. Wilson used data derived from his data request to construct the "Itron sales forecast," and then used his estimated load factors to translate the "Itron forecast" into a peak demand forecast.

In Figure JFW-D (page 25 of APV Witness Wilson's testimony), he compares the sum of the "Itron sales forecast" model output with the Company's sales forecast and notes the 1.9% difference between the forecasts (with the "Itron sales forecast" being lower). Figure JFW-D from page 25 of Mr. Wilson's testimony is shown below:

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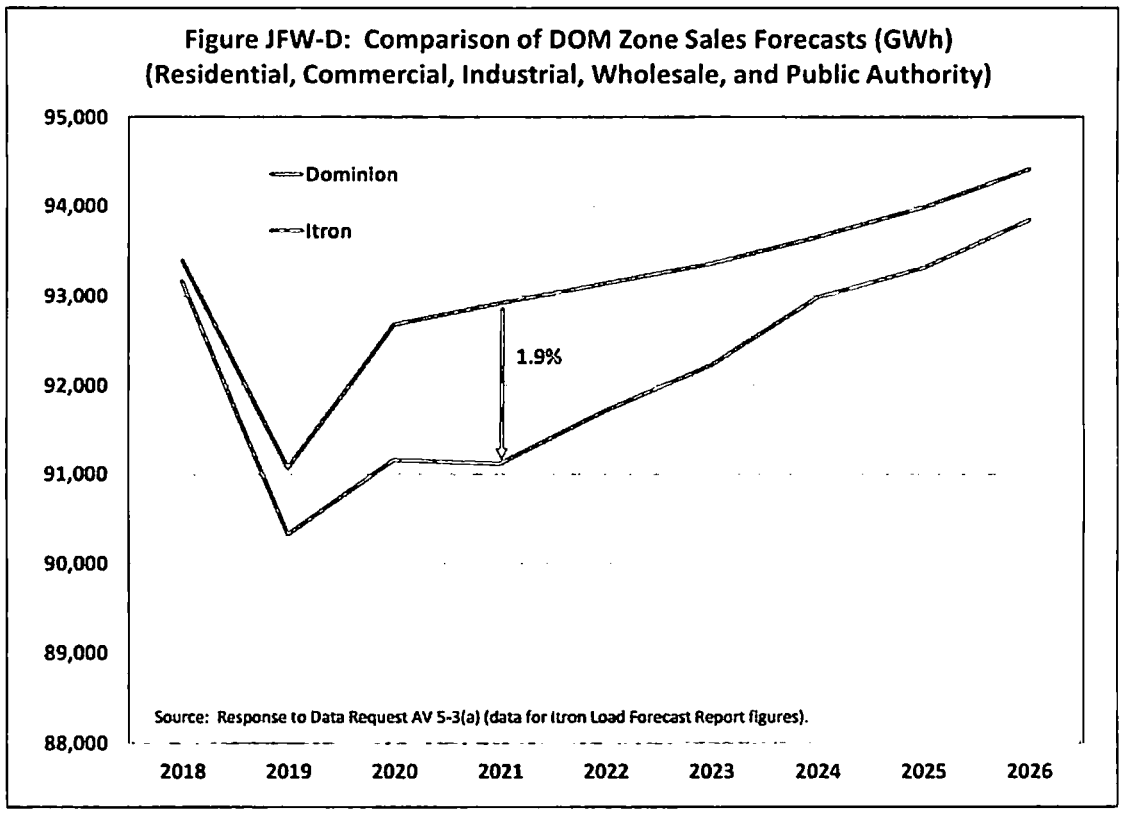
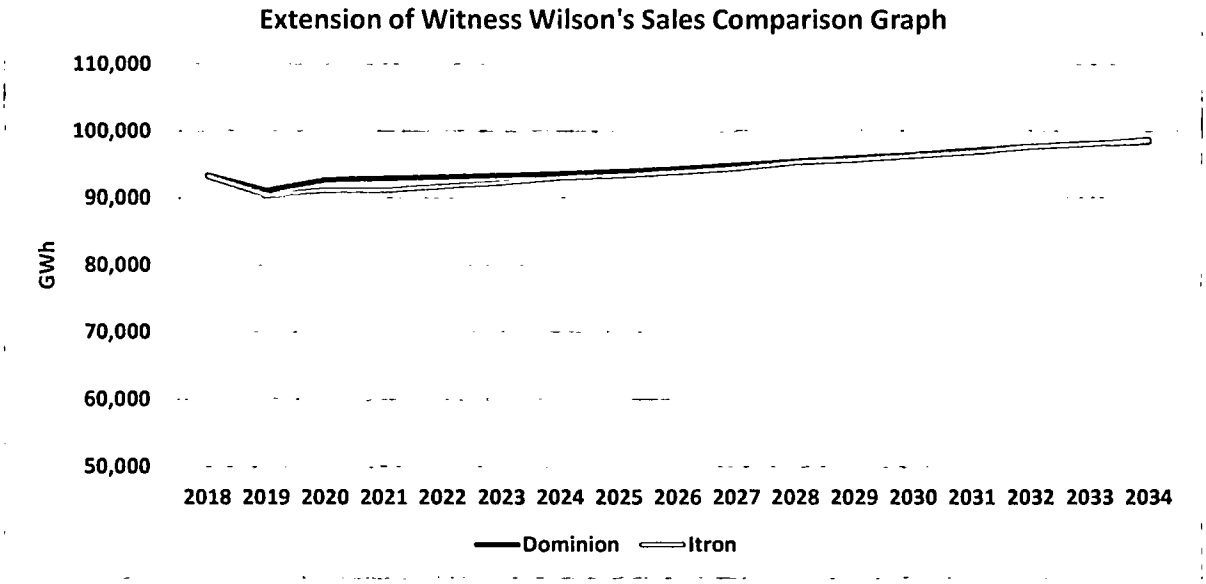
Figure JFW-D



What Mr. Wilson fails to note is that most of the difference is because the "Itron forecast" has a lower 2019 starting point as a result of differences in the estimation period (Itron had sales data through June 2019, the Company had data through November 2019) and the Company forecast has a stronger sales rebound in 2020. Adjusting for these differences, the 1.9% difference APV Witness Wilson shows in 2021 falls to 0.3%. If Mr. Wilson extended his graph a couple of years, it would show that by 2028 the gap between the two forecasts falls to just 0.2%. Rebuttal Figure JFW-D (EXTENDED) below shows Mr. Wilson's comparison if it is extended through the forecast period, using the Company's sales forecast (shown as "Dominion") and Mr. Wilson's "Itron sales forecast" (shown as "Itron").

Rebuttal Figure JFW-D (EXTENDED)



There is little difference in forecasted growth; Company forecast (excluding data centers) averages 0.4% annual growth between 2020 and 2030 compared with Mr. Wilson's "Itron forecast," which averages 0.5% annual growth over this period. It is also important to note that the "Itron forecast" was based on an earlier economic forecast and incorporated U.S. Energy Information Administration ("EIA") Southeast Census end-use intensities, while the Company forecast is based on end-use intensities calibrated to service area appliance saturation surveys. All these elements considered; it is quite reasonable that the forecasts will be different. The long-term trends, however, are consistent. To that end, Itron concluded on page 1 of the Itron Study that "the current Dominion model provides reasonable projections for long-term resource planning...." The Itron Study also suggested several actions for improving the process, all of which have already been included in the Company's load forecasting process or are being evaluated for inclusion in future Company load forecasts.

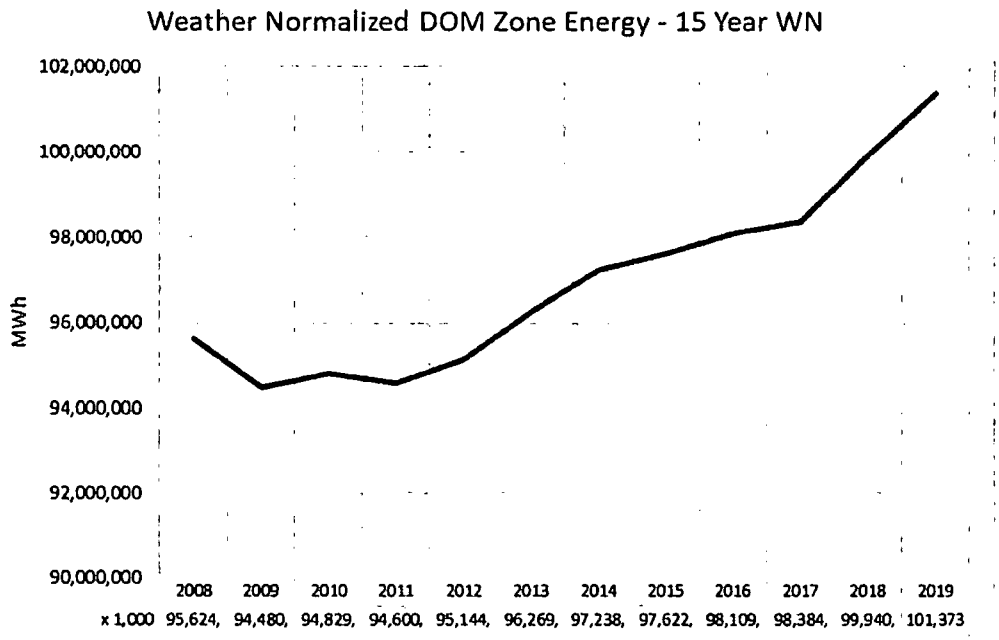
Q. APV Witness J. Wilson also notes on pages 6 and 18-26 of his testimony that the Itron Study included "alternative forecasts" that were generally lower than the Company's, and asserts that these "alternative forecasts" are more accurate than either PJM's or the Company's. Mr. Wilson further recommends on page 11 that the Company should present recent weather normalized historical peak loads and discuss recent trends in its future Plan filings. Please respond.

A. For purposes of this 2020 Plan, APV Witness Wilson's criticism of the Company's load forecast and Itron's "alternative forecast" (which I discussed above) serve no purpose. The Company used the 2020 PJM Load Forecast for the DOM Zone as the basis of all its Alternative Plans put forward in the 2020 Plan in accordance with Commission requirements.

The above paragraph notwithstanding, I will make a few comments. Mr. Wilson continues to assess the DOM Zone historical peak demand by using restricted DOM Zone peak demand figures that have been weather normalized by a process created by PJM. The Company does not weather normalize historical peak demand figures because the results are spurious. Furthermore, PJM has acknowledged on several occasions that it does not use weather normalized peak figures for anything associated with its load forecasting process and only produces them to meet a request of a PJM member. Given that the Company's peak demand is driven by peak producing weather (that may not occur every year), the Company maintains that a better representation of historical peaks is to examine actual unrestricted peaks as reflected in Rebuttal Figure 1 above. Rebuttal Figure 1 clearly shows that both restricted and unrestricted summer peak demand growth has been positive (approximately 1.0% on a compound annual basis). This is in spite of

severe headwinds that have included the adverse economic impact of both the 2007-2009 recession and the Federal sequestration. Rebuttal Figure 2 below reflects weather normalized DOM Zone energy for the period 2008 through 2019, which, again, shows positive growth of approximately 0.5% on a compound annual basis.

Rebuttal Figure 2



On pages 11 and 22 of his testimony, APV Witness Wilson again recommends that the Company shorten the forecast model estimation period to 10 years. To that end, the Company has modified its load forecasting process consistent with that recommendation and Itron's recommendation to shorten the estimation period from 30 years to 10 to 20 years. The Company is now using a rolling 15-year historical period for model estimation along with a rolling 15-year weather history in its weather normalization process. The Company elected to use a rolling 15-year period because a 10-year period (*i.e.*, 2010 to 2019) is disproportionally impacted by a period of weak economic growth

in Virginia that includes the after-effects of the 2007-2009 recession along with the Federal sequestration; a 15-year period (*i.e.*, 2005 through 2019) encompasses a more representative sample of Virginia economic activity.

Q. On pages 25 and 26 of his testimony, APV Witness Wilson presents a DOM Zone summer peak demand forecast he developed and compares that forecast to that the Company's and PJM's summer peak demand forecast. Please comment.

A. APV Witness Wilson's forecast uses the Itron sales forecast presumably scaled up using simple ratios to resemble a Zonal Peak demand forecast. Besides being over-simplistic, Mr. Wilson's forecast is based on "Itron sales forecasts" that Itron never intended to be used as a forecast, but rather a set a tools to help assess the reasonableness of the Company's load forecasting process. As mentioned above, Mr. Wilson's "Itron sales based" forecast is based on an entirely different set of input data than that used in the Company's forecast.

Mr. Wilson is also critical of the Company's and PJM's forecasts, suggesting that both forecasts relied on stale data prior to the COVID-19 pandemic (*see*, *e.g.*, Wilson at 4). However, the same can be said regarding Mr. Wilson's peak demand forecast since it relies on data that is less current relative to that used by the Company and PJM in development of the 2020 DOM Zone load forecasts.

Q. On pages 31-36 of her Report, Staff Witness Johnson criticizes the Company's and PJM's use of econometric methods to forecast energy load, preferring, instead, the artificial neural network technology employed by Enverus. Please comment.

A. Enverus uses an artificial neural network ("ANN") model to develop its forecasts, which

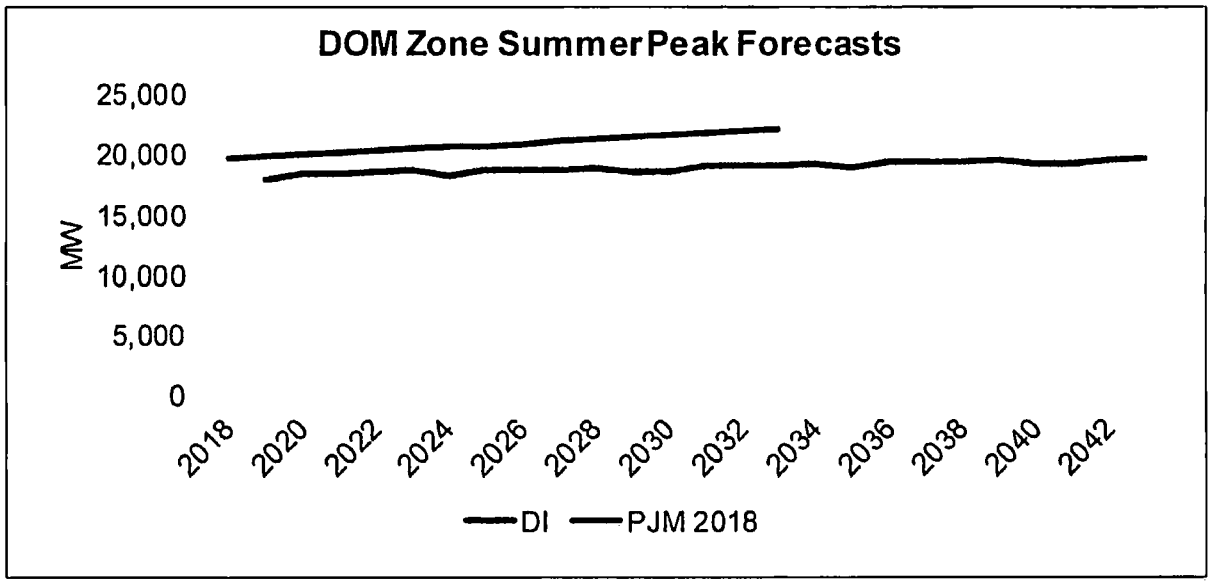
I assume uses only historical weather as the sole explanatory variable. The Company has used neural network models for more than 30 years and has found them to be very useful operationally in predicting short-term load and energy needs on an aggregate level. By short term, I am referring to the next day up to the next seven days. Beyond two days, however, weather forecasts begin to substantially lose their accuracy and, as such, so does the accuracy of ANN model results. The Company has also found that ANN model output is highly dependent on recent historical load events caused by weather and outages. Such events have a tendency to overcompensate in the later stages of the forecast. For example, load events from yesterday influence the 7th day of a weekly load forecast.

Most importantly, ANN models reveal very little, if any, cause and effect relationships, which are important in load forecasting to understand why load is or is not materializing. In contrast, econometric forecasting utilized by the Company has more transparency.

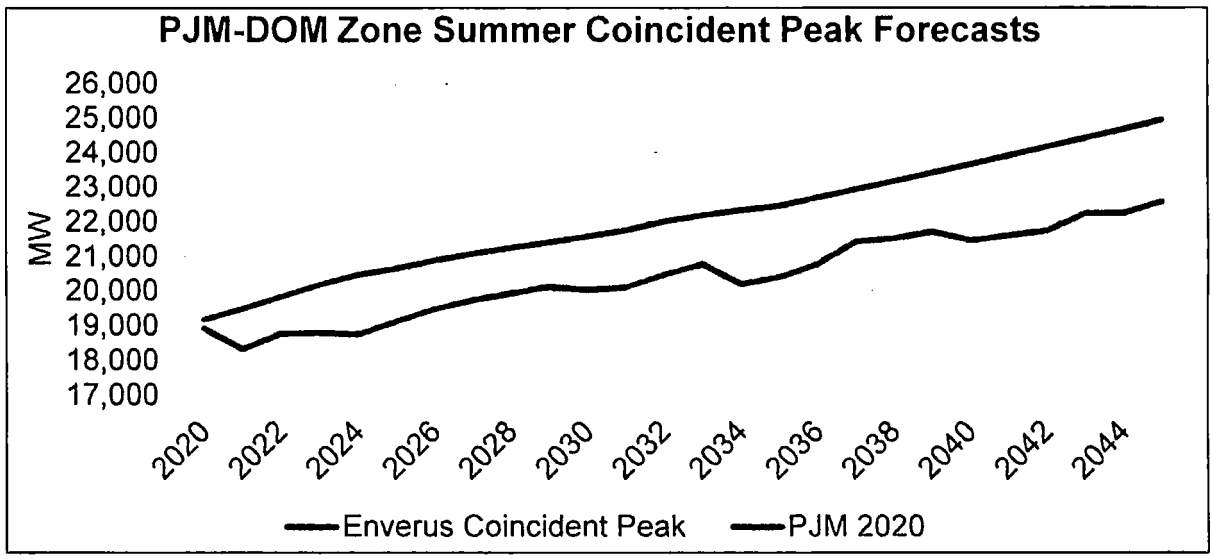
Enverus provided forecasts in the 2018 Plan proceedings using similar ANN modeling. I thought it useful to compare the Enverus 2018 forecast against their forecast in this 2020 Plan proceeding. Since Staff Witness Johnson did not include a non-coincident summer DOM Zone peak demand forecast in her testimony, I had to compare the Enverus 2018 non-coincident summer DOM Zone forecast to its 2020 coincident peak forecast. As a reminder, the DOM Zone summer coincident peak has been and is expected to be lower than the non-coincident peak albeit the trends and growth rates are directly correlated. Nevertheless, Rebuttal Figure 3 below shows the Enverus (formerly Drilling Info, Inc.) DOM Zone non-coincident peak demand forecast from the 2018 Plan proceeding (green

line), while Rebuttal Figure 4 reflects the Enverus current DOM Zone coincident peak forecast (green line).

Rebuttal Figure 3



Rebuttal Figure 4



The 2018 Enverus non-coincident forecast (Rebuttal Figure 3) reflects a flat growth rate that never surpasses 20,000 MW for the period of the forecast. The Enverus 2020

coincident DOM Zone forecast (Rebuttal Figure 4) reflects a positive growth rate that surpasses 20,000 MW around 2028. Recall from Rebuttal Figure 1 above that the DOM Zone set an all-time summer peak this past July that was well in excess of 20,000 MW. Given the ANN framework, it makes it difficult if not impossible to understand why this dramatic change in forecasts has occurred. This example reflects one of the issues of using ANN models for long-term forecasting—it is difficult to answer "why" forecasts change from year to year.

Q. On pages 9-11 of his testimony, APV Witness J. Wilson asserts that the Company performed reserve margin and total resource requirements ("TRR") calculations using the installed capacity measure, which likely resulted in substantially overstating the reserve requirements, and provides alternative estimates. Mr. Wilson further asserts on page 18 that the inaccuracy of the Company's peak load forecasting has resulted in repeatedly over-stating future capacity needs (TRRs) by thousands of MW. Please respond.

A. In order to determine its capacity requirements, PJM utilizes a method known as un-forced capacity or "UCAP." This measure adjusts a generating unit's capacity rating based on its (or its class average) historical forced outage rate. PJM then adjusts its pool-wide planning reserves by the pool-wide average forced outage rate in order to assure consistency in assessing supply and demand. As I explained in prior Plan proceedings, Mr. Wilson's proposed approach would be difficult to calculate and would lack accuracy, given that the Company does not own or operate all of the generation within the DOM Zone. Rather than using UCAP ratings for its generation resources, the Company has

always used installed capacity ratings or "ICAP." As such, there is no need to adjust planning reserve requirements.

Q. On page 14 of his testimony, APV Witness J. Wilson comments generally as to load growth relative to Virginia's economic growth, recommending on page 12 that the Company should prepare higher and lower long-term load forecast scenarios to reflect uncertainties about the pace of economic growth in future Plan filings. Please comment.

A. APV Witness Wilson makes several statements relative to lower economic growth in the U.S. and Virginia because of the COVID-19 pandemic and how that lower economic growth translates to lower electricity demand. These statements infer that electricity demand is directly related to economic growth.

Compare this inference to Mr. Wilson's testimony in the 2017 Plan proceedings wherein he infers the opposite. From page 20 of his 2017 Plan proceeding testimony, Mr. Wilson stated: "Peak loads can be flat or declining while economic and demographic measures rise due to the increasing penetration of increasingly energy-efficient appliances; people and businesses are doing more with electricity, while using less electricity." Using this logic, low economic growth will not necessarily lead to lower electricity demand.

While I agree with APV Witness Wilson that electricity demand is directly related to economic growth, I point these statements out as an apparent contradiction in Mr. Wilson's prior and current testimony. Further, given the peak demand and sales figures shown above in my testimony, the preliminary impact of COVID-19 on the economy and electricity demand appears to be a short-term phenomenon in Virginia.

As to APV Witness Wilson's recommendation regarding the use of a higher and lower load forecast in future Plans, such a recommendation is reasonable. The Company did include a sensitivity analysis in the 2020 Plan using the Company's internal load forecast; however, because of the similarities to PJM's load forecast, the difference in cost and generation expansion plans were minimal. The Company will incorporate Mr. Wilson's recommendation in future Plans.

Q. On pages 46-47 of his testimony, APV Witness J. Wilson describes how the Company determined the DOM LSE adjusted summer peak load forecast that is used in the TRR calculations. Mr. Wilson further recommends on page 12 that the Company should provide an explicit forecast of the peak loads of the DOM LSE, with a discussion of recent trends in the DOM LSE and other LSE peak loads. Please comment.

A. The Company monitors its share of peak load and energy in the DOM Zone and historical regression trends in the load ratio share. In the past, the Company has determined its share of the DOM Zone for both annual peak hours and for monthly energy. In this 2020 Plan, the Company revised its methods to only use the monthly energy load ratio share for estimating its Zonal share of both peak and energy. This revision was incorporated because the energy data is a more stable metric relative to annual peak data, which, in the Company's view, provides greater accuracy since it is less likely to be skewed by outliers. The results of the 10-year rolling regression are shown in Rebuttal Figure 5 below.

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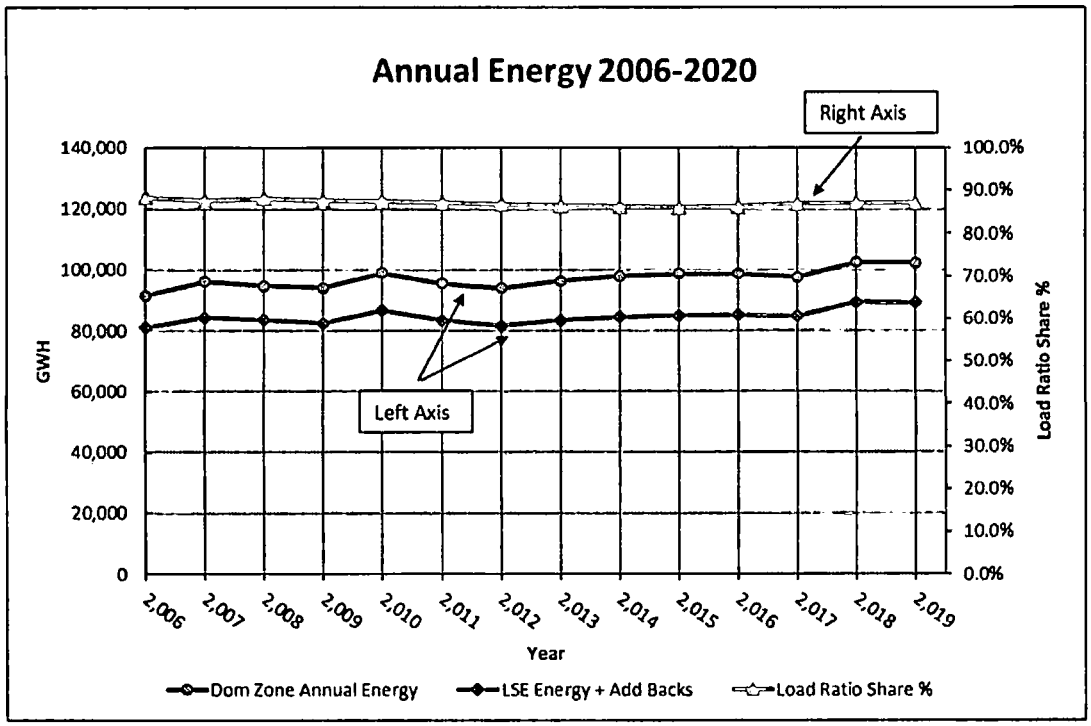
Rebuttal Figure 5



The results indicate a DOM LSE load ratio share of the DOM Zone equal to approximately 86%. This figure was then applied to the PJM peak and energy forecast to estimate the Company's portion of the DOM Zone. As noted in the 2020 Plan, this figure was further decreased to account for future energy efficiency, conservation voltage reduction, and customer choice losses—all of which effectively lower the Company's share of the DOM Zone.

Q. APV Witness J. Wilson further asserts on page 48 that the Company's approach to determining the DOM LSE portion of the DOM Zone peaks is not accurate, in that the regression should be based on peak loads, not energy. Please comment.

A. As described above, the Company elected to revise its methods for estimating its peak demand share of the DOM Zone due to more stable nature of energy data relative to the annual peak demand data, which can easily be skewed by outliers.

Q. On pages 49-52 of his testimony, APV Witness J. Wilson asserts that the Company did not calculate reserve margins and capacity needs in accordance with how capacity obligations are determined in PJM, and offers an example of two different approaches to calculating reserve requirements. Please comment.

A. As explained above in my testimony, the Company uses the ICAP standard because it has no knowledge of the forced outage ratings of other generators within the DOM Zone.

I would also note that on page 53 of his testimony, APV Witness Wilson includes an example of how the PJM capacity market could clear at higher reserve levels, but total capacity costs would be low because the clearing price is lower. However, this is not always the case in the PJM RPM market. Rebuttal Figure 6 below shows how the clearing price/reserve margin relationship could result in both higher and lower total costs to customers.

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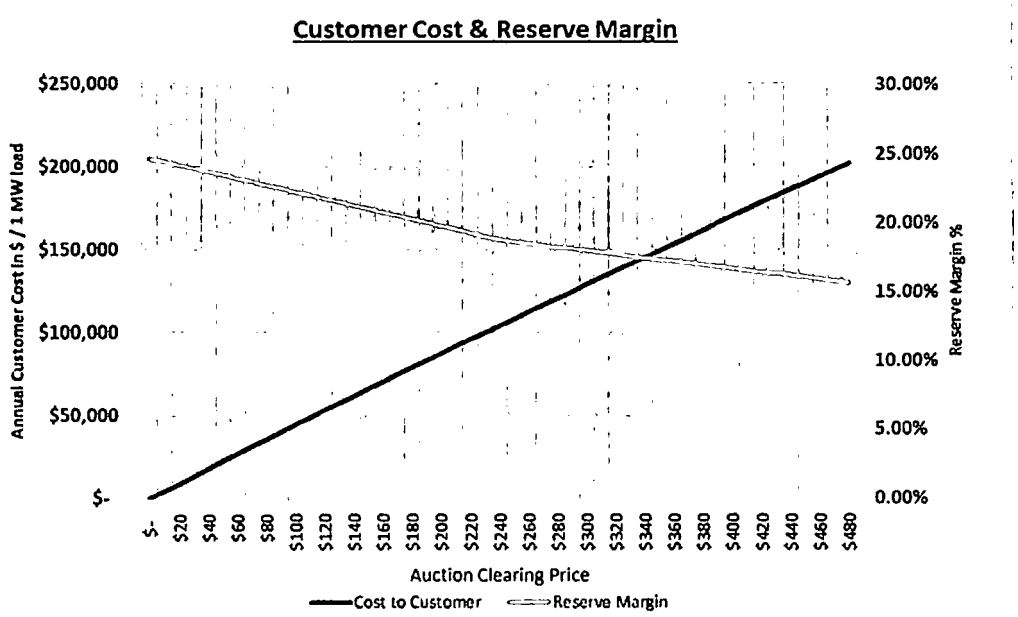
Rebuttal Figure 6



Q. On pages 7-8 of his testimony, Staff Witness White suggests that the Company "complied somewhat" with the directive to use the PJM Load Forecast; however, Staff is concerned that the Company's decision to add back BTM generation to the PJM Load Forecast could distort the forecast in future Plan filings. Please respond.

A. To clarify, the Company did not "add back" BTM generation to the PJM Load Forecast in its evaluation of the Alternative Plans in the 2020 Plan. On page 40 of the 2020 Plan the Company states:

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

Staff Witness White apparently misinterpreted Figures 4.1.1 and 4.1.2 of the 2020 Plan, which compare PJM's load forecast to the Company's. For equal comparison purposes,

the Company added back PJM's forecast of BTM solar generation to its 2020 load forecast only for use in these comparative charts. All Alternative Plans utilized and were based on the 2020 PJM coincident DOM Zone peak and energy forecast inclusive of PJM's adjustments for BTM DERs.

Q. Staff Witness White additionally recommends in his summary and on pages 7-9 of his testimony that the Company should continue to use the PJM coincident peak load forecast and energy sales forecast, scaled down to the DOM LSE level in future Plan and Update filings. Please respond.

A. The Company plans to continue to follow the Commission Order to use the PJM forecast for planning purposes until such order is changed or revised.

II. DATA CENTER FORECASTS

Q. At the outset of his testimony, APV Witness J. Wilson notes that both the PJM and Company forecasts include a separate forecast of data center loads developed by Itron (at 5), and concludes that this separate data center forecast has a significant impact on the PJM and Company forecasts due to the fact that data centers are the only source of peak load growth for the Company, as peak demand for all other customers is actually decreasing (at 7). Do you agree?

A. No, I do not. Clearly, data centers loads have grown at a significant pace within the Company's service territory over the past decade, and that growth is expected to continue for the foreseeable future. APV Witness Wilson's claim, however, that all other customer classes are decreasing is simply false. In 2019, the Company's residential class sales growth was approximately 1.3%. Through August 2020, that same residential sales class growth has been approximately 4.5%. Given that residential customer electricity

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demand is highly weather sensitive, this growth in the residential class likely contributed to the all-time summer peak demand record for the DOM Zone (approximately 20,800 MW) set in July of this year (see Rebuttal Figure 1 above).

Q. On page 5 of his testimony, APV Witness Wilson states: "Both the PJM forecast and the Company's forecast include a separate forecast of data center loads, developed by the Company's consultant Itron, Inc." Do you agree?

A. No, I do not. The Company provides its five-year data center forecast to PJM for use in its load forecasting process. PJM uses that information to develop its own data center forecast for the DOM Zone. To the best of the Company's knowledge, PJM's process is different than that of the Company.

Q. On page 7 of his testimony, APV Witness Wilson states that the Company's data center forecast is unsupported, as it was prepared by Itron using only the Bass Diffusion Model, an inadequate approach and inappropriate methodology that uses only historical data. Please comment.

A. Despite APV Witness Wilson's arguments serving no purpose given that the Company has used the 2020 PJM Load Forecast for the DOM Zone in the 2020 Plan, I feel a few additional comments are necessary.

One of Mr. Wilson's primary issues is that the forecast is based on historical data only. This data served as the basis for developing a long-term demand forecast. Itron reasonably assumed that data center demand would follow an S-shaped curve. Virtually all new technologies have followed an S-shaped adoption path. One that starts off slowly, then accelerates and eventually flattens out as the market or product reaches

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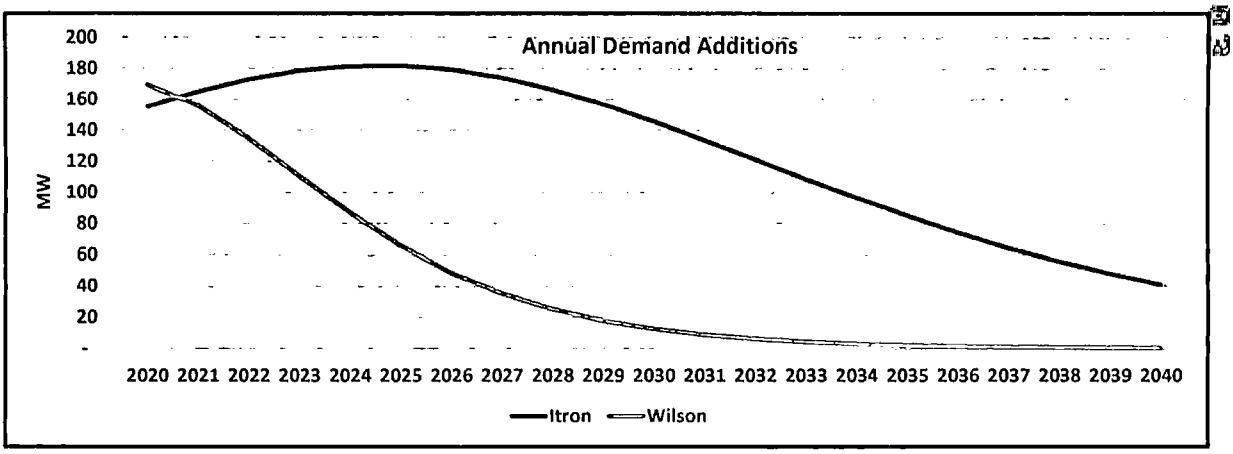
100% saturation. Itron assumed that with demand now growing over 200 MW per year, we are on the steep part of the curve, and that adoption will slow over time until reaching 100% saturation at some point in the future. Itron used a Bass Diffusion Curve for constructing the S-shaped profile. Bass Diffusion Models have been used since the mid-1960s for forecasting thousands of different products and services. The adoption (Bass Diffusion) curve used to forecast data center load in the 2020 Plan was fit to ***both*** historical data center load and expected data center additions over the next five-year period.

Mr. Wilson states on page 7 of his testimony that the Bass Diffusion Model is not appropriate for forecasting data center demand. There are other S-shaped models such as a Logistic Curve or Gompertz Curve, and yet Mr. Wilson used the Itron Bass Diffusion Model provided to him as part of a data request to construct his own data center demand forecast. Mr. Wilson found that if he selected a different reference point used in converting the saturation projection to MW, he could get a better statistical fit (the Itron fatal flaw). However, this only considers the historical data series and is inconsistent with expected near-term data center growth. APV Witness Wilson's forecast reflects flat to declining data center growth in as early as 2021, which is not a likely outcome given the Company's near-term data center interconnection expectation. Rebuttal Figure 7 below compares Itron's expected annual demand additions with Mr. Wilson's projections.

Rebuttal Figure 7

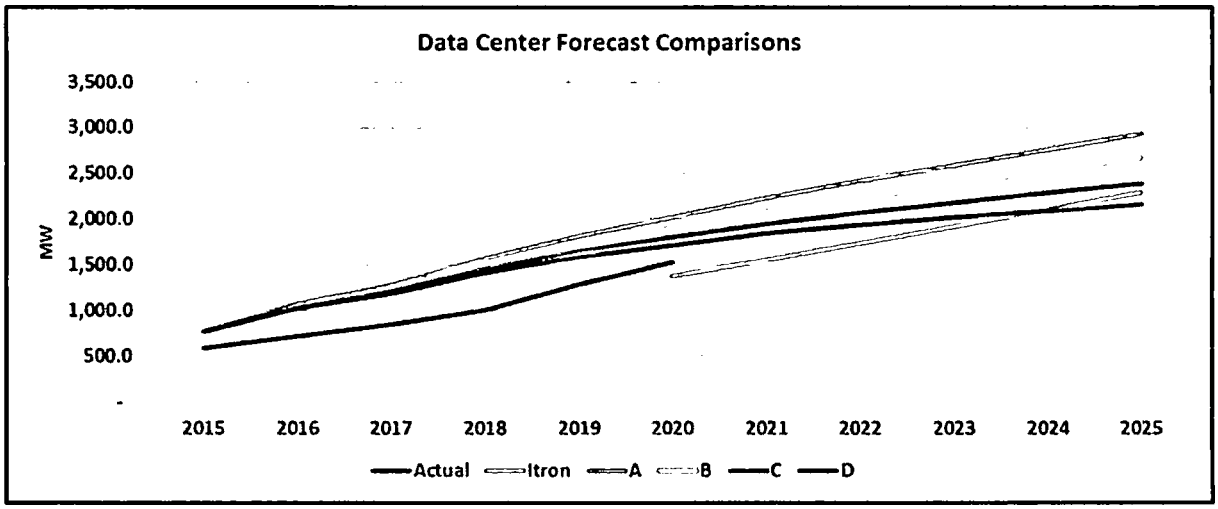


In his testimony, Mr. Wilson maintains that Quanta Technology ("Quanta") developed a much better data center demand forecast that was more forward-looking based on data center research that included discussions with industry experts. In preparing its data center assessment, Itron performed similar research and did confer with Company data center experts. Given that these experts have been facilitating data center load since before 2010, they can reasonably be considered industry experts with respect to data center electricity demand. Further, Itron validated its forecast against data center market data.

Rather than debate the superiority of various methodologies, a more helpful exercise would be to plot out the 2015 Quanta data center load forecast from 2015-2025, and then compare it to the Company's data center load growth (2015-2020) and current data center load current forecast prepared by Itron (2020-2025). In 2015, Quanta prepared for the Company four different data center load forecasts (A through D) and recommended the Company plan for data center growth consistent with their forecast B. Rebuttal Figure 8 below shows each of the four data center forecasts put forth by Quanta ("A, B, C, D")

along actual data center load growth ("Actual") and the Company's current data center load forecast included in the 2020 Plan ("Itron").

Rebuttal Figure 8



From Rebuttal Figure 8 it is apparent that all of the Quanta forecasts have been high relative to both the actual data center loads and the Company's current forecast utilizing the Itron Bass Diffusion Model. The Quanta forecast was not unreasonable at the time, as Quanta had significantly less historical data center demand data available.

In summary, Itron developed a reasonable long-term forecast using a well-accepted modeling approach utilizing a long history of demand data that is consistent with expected near-term capacity additions and data center market data.

Q. On page 39 of his testimony, APV Witness J. Wilson asserts that, to the extent data center loads will grow, these facilities do not rely on the Company for the reliability of their electric supply, as they all have 100% back-up on-site diesel generation. Please comment.

A. This statement is incorrect. To the Company's knowledge, data centers do not run their operations using on-site back-up diesel generation for two primary reasons. First, all data centers are subject to air permits that limit the number of hours on-site back-up diesel generation can be operated in non-emergency situations. Second, it is more economical to use power supplied from the Company than power supplied from diesel fuel. Thus, data centers are dependent on the Company for reliability of their electric supply.

III. SOLAR INTEGRATION COSTS

Q. On pages 24 and 30 of his testimony, APV Witness Rábago asserts that a major deficiency of the 2020 Plan is the "dubious" planning assumptions regarding solar integration costs, citing two major issues. The first major issue is that the Company conducted its power flow modeling assessment based on an assumption that 7,000 MW of random solar project types will be randomly deployed in the Company's service territory, a notion that is unreasonable and unrealistic. Please respond.

A. APV Witness Rábago is incorrect. The population of available solar sites was not random but was, rather, based on PV solar sites included in the PJM queue that are within the Company's service territory. These sites are active locations currently under development for future solar PV resources.

Q. On pages 24 and 31 of his testimony, APV Witness Rábago identifies another major deficiency in that the 2020 Plan assumes no value in, and does not evaluate, geographic spread in renewable energy deployment, or the potential capacity or transmission benefits associated with geographic spread. Please comment.

A. This is not true. Both the re-dispatch costs and regulating reserve costs factor in renewable geographic diversity within the PJM footprint. With respect to DERs, the Company used the PJM Load Forecast for both the development of the 2020 Plan and transmission planning activities. Given that PJM subtracts DER dependable capacity from its load forecast, the avoided cost benefit is indirectly factored into the 2020 Plan and also any transmission planning activities.

Q. While Staff took no position on the reasonableness of the Company's solar interconnection and integrations cost estimates (Cizenski at 7), Staff Witness Cizenski noted certain limitations on the Company's analysis, including (i) assessed under steady state—not dynamic—conditions; (ii) did not include solar PV interconnection and integration costs at the distribution level; (iii) power flow analysis limited to 7,000 MW; and (iv) did not include distribution substation upgrade costs or transmission upgrade costs needed for solar back feed (Cizenski at 8). Please comment.

A. The challenges associated with transforming the Company's power system to meet the requirements of the VCEA are many. That said, the Company is committed to meeting those challenges while maintaining the highest standards of system reliability. To that end, the Company has and will continue to enhance its analysis processes to better assess the requirements and cost of integrating large volumes of inverter-based generation at

both the transmission and distribution levels with lower levels of traditional generation sources. As these assessments are completed, the Company will include the results in future Plans. The Company plans on addressing the items suggested by Staff Witness Cizenski along with other known issues such as system inertia, primary and secondary frequency control, power quality, reactive power, and short circuit strength.

Q. Additionally, Staff recommended the following for future filings: (i) include distribution level solar PV interconnection and integration costs; (ii) include costs of upgrading the transmission grid to address potential reverse power flows from the distribution grid to the transmission grid; and (iii) perform additional analyses utilizing quantities of solar generation and energy storage that are consistent with the plans set forth in the Company's future Plans (Cizenski at 9). Please respond.

A. Again, as I noted above, the Company will continue to enhance its analysis processes to better assess the requirements and cost of integrating large volumes of inverter-based generation, and will include the results of these assessments in future Plans consistent with Staff Witness Cizenski's recommendations.

Q. Mr. Thomas, does this conclude your rebuttal testimony?

A. Yes, it does.

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