COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PREFILED STAFF TESTIMONY

VIRGINIA ELECTRIC AND POWER COMPANY

In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq.*

Public Version

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PUR-2020-00035

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PART A

Summary of the Testimony of Gregory L. Abbott

My testimony addresses Virginia Electric and Power Company's ("Company") 2020 Integrated Resource Plan ("IRP"). Staff does not take a position on whether the Company's 2020 IRP is reasonable and in the public interest pursuant to § 56-599 C of the Code. Staff does find, however, that the Company's 2020 IRP contains several deficiencies including failure to fully account for the effects of the Virginia Clean Economy Act ("VCEA"). More specifically, my testimony:

- Provides an overall summary of Staff's major findings and recommendations;
- Provides an overview of recent major changes in legislation and implications for the long-term planning process;
- Describes changes in the level of information provided in IRPs in recent years, the lack of transparency in the 2020 IRP, and makes recommendations for information and analyses that the Commission consider requiring in future IRP filings;
- Discusses the inadequacy of the Company's modeling of energy storage resources;
- Discusses the results of the Company's generation unit retirement analysis and implications for the 2020 IRP plans presented by the Company;
- Provides an overview of the implications of the Company's proposed energy efficiency programs on typical residential bills; and
- Discusses the need for more transparency in the Company's rendering of bills to customers.

A summary of Staff's primary findings and recommendations is presented below:

- Staff calculates that the Company's plan to comply with the VCEA will result in a typical monthly bill for a residential customer using 1,000 kilowatt hours to increase to **$183.50** in 2030. This represents an increase of **$67.32** or 58% compared to the typical monthly bill as of May 1, 2020 and an annual increase of **$807.84**;
- The Company's Plan D fully models the policy goals of the VCEA including being 100% carbon free by 2045. Plan D has an net present value ("NPV") cost of **$84.3 billion**;
- Each of the Company's plans designed to comply with the VCEA overbuilds for purposes of (i) meeting peak load requirements, (ii) meeting energy requirements, and (iii) satisfying the annual mandatory Renewable Portfolio Standards ("RPS") requirements;
- The Company's least-cost Plan A does not appear to have fully complied with prior Commission directives that the Company must not force the modeling to select any resource or exclude any reasonable resource for purposes of its least-cost plan;

- The Company did not develop a least-cost VCEA-compliant plan. Each of the Company's plans designed to comply with the VCEA includes (i) an expensive second tranche of offshore wind, (ii) an expensive pumped storage unit, and (iii) continues to operate the uneconomic Virginia City Hybrid Energy Center ("VCHEC") unit through 2045;
- A least-cost VCEA-compliant plan may reduce the typical residential monthly bill impacts compared to the Company's plans to comply with the VCEA. Staff recommends that, in future IRPs, the Company be directed to develop a least-cost VCEA-compliant plan as a benchmark against which to assess incremental costs of other plans the Company may wish to pursue;
- Continuing the operation of VCHEC reflects an additional NPV cost of $472 million imposed on customers that is significantly higher than the NPV cost savings to customers from all other retiring units combined;
- Staff recommends, for any subsequent application seeking a certificate of public convenience and necessity ("CPCN") for a generation or battery storage resource, or for cost recovery, that such filing be based on modeling that utilizes updated commodity price forecasts that reflect the impacts of the VCEA;
- There is a lack of transparency in the Company's modeling process for the 2020 IRP. To address this lack of transparency, Staff recommends that the Commission require the Company to perform numerous sensitivity analyses in future IRP filings. Staff further recommends that the Commission require the Company to provide all input files that are used in the PLEXOS modeling, or any other modeling software used by the Company, to Staff and any other party that requests this data in future IRPs, CPCNs, or any cost recovery filings where the Company uses such software;
- All of the Company's VCEA-compliant plans include building 970 megawatts ("MW") of new natural gas-fired combustion turbines ("CTs"), 485 MW in 2023 and 485 MW in 2024, as a placeholder to address what the Company characterizes as probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities;
- The Company has not performed any detailed analysis of system reliability that would demonstrate a pressing need for the construction of 970 MW of gas-fired CTs at the beginning of the planning period. Staff questions the appropriateness of inclusion of CTs as placeholders absent any actual detailed analysis of system reliability that identifies specific issues, including the timing of those issues, that must be addressed. Such an analysis should also identify the optimal solutions to such problems which may or may not be a gas-fired CT; and
- Staff recommends that the Commission direct the Company to propose, in its upcoming triennial review, revisions to its residential bill format in conformance with 20 VAC 5-312-90 of the Commission's Rules Governing Retail Access to Competitive Energy Services to allow more transparency into how bills are calculated and to more fully show the impacts associated with the implementation of the VCEA.

PUBLIC VERSION

PREFILED TESTIMONY
OF
GREGORY L. ABBOTT

VIRGINIA ELECTRIC AND POWER COMPANY'S
INTEGRATED RESOURCE PLAN FILING

CASE NO. PUR-2020-00035

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE VIRGINIA STATE CORPORATION COMMISSION ("COMMISSION").

A1. My name is Gregory L. Abbott. I am a Deputy Director in the Commission's Division of Public Utility Regulation.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. My testimony addresses Virginia Electric and Power Company's ("DEV," "Dominion," or "Company") 2020 Integrated Resource Plan ("IRP") filed in compliance with the Commission's March 9, 2020 Order in this proceeding. Specifically, my testimony:

- Provides an overall summary of Staff's major findings and recommendations;
- Provides an overview of recent major changes in legislation and implications for the long-term planning process;
- Describes changes in the level of information provided in IRPs in recent years, the lack of transparency in the 2020 IRP, and makes recommendations for information and analyses that the Commission consider requiring in future IRP filings;
- Discusses the inadequacy of the Company's modeling of energy storage resources;

- Discusses the results of the Company's generation unit retirement analysis and implications for the 2020 IRP plans presented by the Company;
- Provides an overview of the implications of the Company's proposed energy efficiency ("EE") programs on typical residential bills; and
- Discusses the need for more transparency in the Company's rendering of bills to customers.

<u>SUMMARY OF FINDINGS AND RECOMMENDATIONS</u>

Q3. PLEASE PROVIDE AN OVERALL SUMMARY OF STAFF'S FINDINGS AND RECOMMENDATIONS.

A3. Staff does not take a position on whether the Company's 2020 IRP is reasonable and in the public interest pursuant to § 56-599 C of the Code. Staff does find, however, that the Company's 2020 IRP contains several significant deficiencies including failure to fully account for the effects of the Virginia Clean Economy Act ("VCEA"). To some degree this is not surprising 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 IRP by May 1, 2020.[1]

A summary of Staff's primary findings and recommendations and the associated Staff witnesses is presented below.

- Staff calculates that the Company's plan[2] to comply with the VCEA will result in a typical monthly bill for a residential customer using 1,000 kilowatt hours ("kWh") to increase to **<u>$183.50</u>** in 2030. This represents an

[1] Staff also notes that the Company could have updated the IRP filing as new information became available. For example, as discussed in Staff's testimony, the Company's commodity price forecasts are stale because they do not reflect the impacts of the VCEA. The Company could have updated these forecasts and provided supplemental testimony reflecting the impacts of the VCEA on the forecasts, and subsequently the build plans, presented in the IRP.

[2] Based on the Company's Plan B_{19} that utilizes the Commission directed baseline assumptions.

increase of **$67.32** or 58% compared to the typical monthly bill as of May 1, 2020 and an annual increase of **$807.84**. (Myers testimony at 2);[3]

- The Company's Plan D fully models the policy goals of the VCEA including being 100% carbon free by 2045. Plan D has an NPV cost of **$84.3 billion** which is $40 billion higher than the Company's least-cost non-VCEA compliant Plan A. (Dalton testimony at 55);

- Each of the Company's plans designed to comply with the VCEA overbuilds for purposes of (i) meeting peak load requirements, (ii) meeting energy requirements, and (iii) satisfying the annual mandatory Renewable Portfolio Standards ("RPS") requirements. (Dalton testimony at 34, 42 and 45);

- The Company's least-cost Plan A does not appear to have fully complied with prior Commission directives that the Company must not force the modeling to select any resource or exclude any reasonable resource for purposes of its least-cost plan. For example, Plan A continues to operate the uneconomic Virginia City Hybrid Energy Center ("VCHEC") coal plant and the Hopewell, Altavista, and Southampton biomass units through 2045. The Company has also limited the amount of solar resources its modeling can select for Plan A to 480 megawatts per year, despite solar being a possible least-cost resource and despite not placing similar annual limits on solar resources in other plans. (Dalton testimony at 55);

- The Company did not develop a least-cost VCEA-compliant plan. Each of the Company's plans designed to comply with the VCEA includes (i) an expensive second tranche of offshore wind, (ii) an expensive pumped storage unit, and (iii) continues to operate the uneconomic VCHEC unit through 2045. (Dalton testimony at 9);

- A least-cost VCEA-compliant plan may reduce the typical residential monthly bill impacts compared to the Company's plans to comply with the VCEA. Staff recommends that, in future IRPs, the Company be directed to develop a least-cost VCEA-compliant plan as a benchmark against which to assess incremental costs of other plans the Company may wish to pursue. (Dalton testimony at 56);

- Continuing the operation of VCHEC reflects an additional NPV cost of $472 million imposed on customers that is significantly higher than the NPV cost savings to customers from all other retiring units combined. (Abbott testimony at 28);

[3] Staff based its class allocation factor for future generation resources on the Company's recent and historic Factor 1 filed with the Commission. Staff does not believe it is appropriate to forecast future class cost allocation factors.

- The Company's commodity price forecasts were completed in the fall of 2019 before the passage of the VCEA and do not reflect the buildout envisioned by that legislation in solar, offshore wind resources and energy storage. These VCEA build plans will have a significant impact on future commodity prices. The failure to account for the VCEA on commodity price forecasts used as inputs into the IRP modeling is a deficiency of this IRP and, as such, the Company may not have fully complied with the Commission's March 9, 2020 Order that directed the Company to model the VCEA in the 2020 IRP. (Abbott testimony at 24);

- Staff recommends, for any subsequent application seeking a certificate of public convenience and necessity ("CPCN") for a generation or battery storage resource, or for cost recovery, that such filing be based on modeling that utilizes updated commodity price forecasts that reflect the impacts of the VCEA. (White testimony at 6);

- There is a lack of transparency in the Company's modeling process for the 2020 IRP. To address this lack of transparency, Staff recommends that the Commission require the Company to perform numerous sensitivity analyses in future IRP filings. Staff further recommends that the Commission require the Company to provide all input files that are used in the PLEXOS modeling, or any other modeling software used by the Company, to Staff and any other party that requests this data in future IRPs, CPCNs, or any cost recovery filings where the Company uses such software. (Abbott testimony at 17);

- Staff believes that the Company's treatment of energy storage resources in the PLEXOS modeling is a significant deficiency in the 2020 IRP. Staff's three primary concerns about the Company's modeling of energy storage resources are: (i) the reduction of the nameplate capacity for battery storage resources input into the PLEXOS model; (ii) the Company's PJM energy price forecasts used in the model which do not reflect the impact of the Company's proposed build plan to comply with the requirements of the VCEA; and (iii) the Company's use of unrealistic values for battery storage resources in the PLEXOS model that are not consistent with the green sheets data. (Abbott testimony at 18);

- All of the Company's VCEA-compliant plans include building 970 MW of new natural gas-fired combustion turbines ("CTs"), 485 MW in 2023 and 485 MW in 2024, as a placeholder to address what the Company characterizes as probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities. (Cizenski testimony at 18);

- The Company has not performed any detailed analysis of system reliability that would demonstrate a pressing need for the construction of 970 MW of gas-fired CTs at the beginning of the planning period. Staff questions the appropriateness of inclusion of CTs as placeholders absent any actual detailed analysis of system reliability that identifies specific issues, including the timing of those issues, that must be addressed. Such an analysis should also identify the optimal solutions to such problems which may or may not be a gas-fired CT. (Cizenski testimony at 18); and

- Staff recommends that the Commission direct the Company to propose, in its upcoming triennial review, revisions to its residential bill format in conformance with 20 VAC 5-312-90 of the Commission's Rules Governing Retail Access to Competitive Energy Services ("Rules") to allow more transparency into how bills are calculated and to more fully show the impacts associated with the implementation of the VCEA. (Abbott testimony at 45).

<u>OVERVIEW OF LEGISLATION IMPACTS ON IRP FILINGS</u>

Q4. PLEASE IDENTIFY THE MAJOR LEGISLATIVE CHANGES THAT HAVE A BEARING ON IRP FILINGS.

A4. Although there are some legislative changes every year that impact electric utility regulation in Virginia, there have been five major laws passed by the Virginia General Assembly that specifically impact IRP filings. These are:

- 2007 Regulation Act[4]
- 2008 legislation
- 2015 Senate Bill 1349 ("SB1349")[5]
- 2018 Grid Transformation and Security Act ("GTSA")
- 2020 VCEA

Q5. WHAT LEGISLATION REQUIRED THE COMPANY TO FILE AN IRP?

[4] This is often referred to as the "Re-Regulation Act."
[5] This is often referred to as the "Rate Freeze Bill."

A5. Chapters 476 and 603 of the 2008 Acts of Assembly required electric utilities to submit, by September 1, 2009, an IRP that provides a forecast of their load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to provide reasonable prices, reliable service, energy independence, and environmental responsibility.[6] It also required formal IRP filings to be filed every two years thereafter. In the intervening years, the Company provided informal update IRP filings. These update filings are not litigated before the Commission and are mainly for informational purposes.

Q6. PLEASE PROVIDE AN OVERVIEW OF THE 2007 REGULATION ACT.

A6. The 2007 Regulation Act established biennial reviews of DEV's base rates following the expiration of capped rates. Under certain overearning conditions, the Commission had the discretion to reduce the Company's base rates and/or order rate refunds. In addition, the 2007 Regulation Act permitted DEV to seek rate adjustment clauses ("RACs"), or "Riders," for recovery of the costs of certain new generation resources on a stand-alone basis separate from base rates.

The 2007 Regulation Act declared that a new coal-fired generation unit located in southwest Virginia that burns Virginia coal to be in the public interest.[7] Additionally, the 2007 Regulation Act provided for an enhanced rate of return for fossil fuel generating plants to provide an incentive for utilities to construct fossil fuel generating units in Virginia. As a result of this legislation, DEV constructed

[6] This legislation added a new Chapter 24 (§ 56-597, et seq.) in Title 56 of the Code comprising the IRP filing requirement.
[7] The coal unit that was ultimately constructed under this Act was the Virginia City Hybrid Energy Center ("VCHEC").

several large fossil fuel units with cost recovery through a RAC. The table below shows the fossil fuel generating units that were constructed by the Company pursuant to the 2007 Regulation Act and the enhanced return each plant received in basis points.[8]

Rider	Generating Station(s)	B.P. Incentive	Term	Initial Case
S	VCHEC (Coal)	100	12	PUE-2007-00066
R	Bear Garden (Gas)	100	10	PUE-2009-00017
B	Biomasss Conversions	200	5	PUE-2011-00073
W	Warren (Gas)	100	10	PUE-2011-00042
BW	Brunswick (Gas)	100	10	PUE-2012-00128
GV	Greensville (Gas)	n/a	n/a	PUE-2015-00075

Thus, in response to the policy goals contained in the 2007 Regulation Act, the Company developed a significant portfolio of coal and natural gas generation units. The Company's customers are still paying an enhanced rate of return on some of these fossil fuel units.

Q7. PLEASE PROVIDE AN OVERVIEW OF SB 1349 ENACTED IN 2015.

A7. This bill was passed against the backdrop of the proposed federal Clean Power Plan ("CPP") which, among other things, introduced a significant amount of uncertainty about the future of energy in Virginia. SB 1349 suspended the biennial base rate reviews established in the 2007 Regulation Act until 2020 for Appalachian Power Company and until 2022 for Dominion, and, consequently, eliminated the Commission's discretion to reduce base rates or order base rate refunds until those

[8] One basis point is one hundredth of a percent. A 100-basis point enhanced return would be equal to a one percent adder.

next biennial reviews. The elimination of the possibility of base rate reductions or refunds led to SB 1349 often being referred to as the "Rate Freeze" bill. This shorthand was a misnomer, however, because the existing RACs were not capped and the Company was not precluded from seeking additional new RACs. Further, the utilities were expressly permitted by this legislation to recover their fuel expenses without interruption, and to seek emergency base rate relief, if necessary.

SB 1349 also directed that IRPs be filed on an annual basis ostensibly to provide additional Commission oversight in lieu of the suspended biennial base rate reviews.

Q8. PLEASE PROVIDE AN OVERVIEW OF THE 2018 GTSA.

A8. Among other things, The GTSA re-established base rate reviews by the Commission to occur every three years (now termed "triennial" base rate reviews). The GTSA further directed that IRPs be filed once every three years, in the year before a utility's triennial base rate review is filed. The GTSA also required the IRP to include the Company's long-term distribution grid plan and electric grid transformation projects. The GTSA further declared certain renewable energy resources to be in the public interest.

Q9. PLEASE PROVIDE AN OVERVIEW OF THE VCEA.

A9. Like the GTSA, the VCEA also declared certain renewable energy resources to be in the public interest, superseding and significantly expanding the quantities contained in the GTSA. The VCEA also included a presumption that, in addition to being in the public interest, the costs of certain offshore wind resources are reasonable and prudent, subject to certain metrics. The VCEA also paves the way for Virginia to participate in the Regional Greenhouse Gas Initiative ("RGGI").[9] The VCEA did not alter the frequency of required IRP filings from the current three-year cycle established by the GTSA. A more detailed discussion of the requirements of the VCEA is contained in the Company's 2020 IRP.[10]

Q10. PLEASE IDENTIFY THE YEARS WHEN THE COMPANY WAS REQUIRED TO FILE A FORMAL IRP.

A10. As noted above, the filing requirements for IRPs have changed from an initial two-year cycle, to a one-year cycle, and then to the current three-year cycle. As such DEV filed formal IRPs in 2009, 2011, 2013, 2015, 2016, 2017, 2018, and 2020. In the intervening years, the Company filed informal IRP updates.

Q11. HAS THE COMMISSION PREVIOUSLY REQUIRED THE COMPANY TO MODEL NEW LAWS BEFORE THEIR EFFECTIVE DATE?

A11. Yes. In prior IRPs the Commission has taken notice of recently enacted legislation, even if not yet effective, and directed the Company to model compliance with the new law in its next IRP. For example, in its Final Order on DEV's 2017 IRP, the Commission took judicial notice of the recent passage of 2018 GTSA, recognizing that the new legislation would impact subsequent IRPs.[11] The Commission directed "that Dominion's future IRPs, beginning with the IRP due to be filed on May 1,

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[9] The 2020 General Assembly also enacted the Clean Energy and Community Flood Preparedness Act which authorizes Virginia to join RGGI. Senate Bill 1027, 2020 Virginia Acts of Assembly Chapter 1280, and House Bill 981, 2020 Virginia Acts of Assembly Chapter 1219.
[10] 2020 IRP at 9-11.
[11] *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-2017-00051, 2018 S.C.C. Ann. Rept. 216, 217, Order (Mar. 12, 2018).

2018, shall include detailed plans to implement the mandates contained in that legislation, as well as plans that comply with all other legal requirements." The Commission noted "[t]his includes, for example, the utility's least-cost plan along with plans compliant with proposed federal carbon-control regulations ..."

Similarly, although the current 2020 IRP was filed prior to the effective date of the VCEA, the General Assembly had passed, and the governor signed, the VCEA before the Company made this IRP filing. As noted earlier, the Commission's March 9, 2020 Order required the Company to model the costs and reliability requirements of the VCEA in this proceeding. This is appropriate because IRPs are planning documents that include forward-looking analyses. As such, it is important to reflect the dictates of the law expected to be in effect during the future IRP planning period.

Q12. HAVE SHIFTS IN PUBLIC POLICY GOALS DELINEATED IN RECENT LEGISLATION COMPLICATED LONG-TERM UTILITY PLANNING?

A12. Yes. Both the 2018 GTSA and the 2020 VCEA represent significant shifts in public policy goals. Further, there is a potential for future changes in federal laws and regulations such as the aforementioned proposed CPP. Such changes can significantly affect a utility's long-term planning.

Many generation units have long lives, relatively long lead times to bring on-line, and large capital costs that are recovered from customers, often over many decades. Given the fluid nature of public policy goals over recent years, Staff generally believes that it may be preferable to address current public policy goals using technologies that can be implemented in smaller increments, are scalable, have relatively short lead times to bring on-line, and that may be reasonably expected to have declining costs over time as the technology continues to develop and mature. Generally, solar resources, battery storage resources, and gas-fired CTs fall in this category.

LACK OF TRANSPARENCY IN IRP MODELING PROCESS

Q13. IS THERE A LACK OF TRANSPARENCY IN THE COMPANY'S IRP MODELING PROCESS?

A13. Yes. The Company utilizes the PLEXOS model to simulate the future operation of its system and to identify the resources required to satisfy load. The PLEXOS modeling software applies least-cost optimization algorithms to replicate the behaviors of the physical power system. By changing the inputs, the analyst can access multiple different courses of action. Given the significant number of model inputs required and the uncertainty that is inherent in forecasting model inputs, such as future commodity prices, the analyst can run scores of various scenarios through the model. Then, the analyst can compare and contrast the findings, selecting the most suitable customized solution.

Although the PLEXOS model is a powerful utility planning tool, it can also be accurately characterized as a "black box." In the current case, only the Company possesses the model and has the expertise to run various scenarios under differing model assumptions.

Similarly, only the Company possesses the detailed input files that are used in the model simulations. The Company's IRP does contain high level summary data that is used in the model such as the commodity price forecasts contained in

Appendix 4O of the IRP. This summary data, however, is not the same detailed granular level data that is input into the model.

The unique costs and operating characteristics of each of the Company's existing generating units and potential future generating units are also model inputs. The Company has provided such generating unit data for potential future generating units to Staff through discovery in this IRP and in prior IRPs. The Company refers to this unit specific data as the "green sheets."[12] The green sheets data provided to Staff in discovery, however, is not exactly the data that is input into the model as the green sheets are apparently reformatted for modeling purposes. As will be discussed later in my testimony, Staff has discovered that the green sheets data does not always accurately reflect the unit data that was input into the model. Thus, this non-transparent reformatting of the green sheets is also part of the black box nature of the Company's modeling.

Q14. HOW HAS THIS LACK OF TRANPARENCY BEEN ADDRESSED IN PRIOR IRP FILINGS?

A14. In most prior IRPs, the Company would run multiple sensitivities on the various plans under consideration. For example, in its 2013 IRP, the Company examined six different plans under 20 different sensitivities/scenarios. Thus, when the 2013 IRP was filed the Company had performed 120 unique model runs which essentially creates a zone of reasonableness around the model results for each plan. Sensitivities can include different assumptions that are subject to uncertainty such

[12] The green sheets data supplied to Staff reflect only potential new generating units made available to the model to select. The Company does not provide this data for existing units, however, similar data for existing units are also input into the PLEXOS model.

as high fuel costs, low fuel costs, high renewable energy credit ("REC") prices, low REC prices, high construction costs, low construction costs, high energy prices, low energy prices, high load growth, low load growth, and others as may be appropriate given the events surrounding a given IRP. The Company stopped providing these sensitivities in its IRPs beginning with the 2016 IRP.

In addition to providing multiple sensitivities in prior IRPs, the Company would also provide model runs as requested by Staff to examine different changes in assumptions or different resource combinations.

The combination of providing various sensitivity model runs when the IRP was filed, along with the Company providing specific model runs requested by Staff through discovery, gave Staff a comfort level with the black box modeling. That is, by examining changes in inputs and the resulting changes in model outputs, Staff could reasonably gain insight into how the model was working and whether it was working adequately.

Q15. WHY DID THE COMPANY STOP PROVIDING THIS DETAILED SENSITIVITY INFORMATION IN ITS 2016 IRP?

A15. As I mentioned earlier in my testimony, in 2015, SB 1349 changed the IRP filing requirements to annual filings. In addition, the Company was grappling with modeling the requirements of the proposed federal CPP which included modeling mass-based approaches, intensity-based approaches, and leakages. Given the burden of meeting an annual IRP filing schedule combined with the high degree of difficulty associated with incorporating the proposed CPP into the modeling process, the Company approached Staff informally and asked to be relieved of the burden of also filing multiple sensitivity scenarios in the 2016 IRP especially in light of the Commission directed risk analysis requirement from a prior IRP. Staff was agreeable to this request with the informal understanding that the Company would be willing to provide sensitivity model runs to Staff through discovery if Staff made specific requests. In the Company's last IRP, the 2018 IRP, the Staff requested, and the Company provided 34 different model runs through discovery.

Q16. HAS THE COMPANY CONTINUED TO PROVIDE MODEL RUNS TO STAFF THROUGH DISCOVERY IN THE 2020 IRP?

A16. No. Although Staff requested numerous model runs through discovery, the Company only provided one additional model run and refused to provide any of the other model runs requested by Staff.[13] Given that the VCEA is a major re-set of energy policy in Virginia, Staff attempted to get model runs (i) with and without the very expensive pumped storage unit contained in all modeled plans, (ii) with and without the second tranche of very expensive offshore wind contained in all modeled plans, and (iii) with and without the gas combustion turbines which are contained in all modeled plans. Staff believes that the results of these model runs would have created a more robust record and provided insight to the Commission on various resource combinations allowed to meet the requirements of the VCEA.

Given the lack of sensitivity runs and the Company's refusal to provide model runs to Staff through discovery, Staff no longer has any comfort level with the model results that have flowed out of the PLEXOS black box modeling process

[13] On August 28, 2020, Staff filed a Motion to Compel two model runs which was granted in part and denied in part on September 16, 2020. As of the time this testimony was being finalized, Staff had not yet received the compelled run.

presented in this IRP. The Company has chosen to evaluate the plans in this IRP under just one set of assumptions. This is particularly concerning given the turbulent state of the energy markets that we are currently experiencing.

Q17. CAN YOU PROVIDE AN EXAMPLE THAT HIGHLIGHTS STAFF'S CONCERNS?

A17. Yes. The IRP is often referred to as an analysis that represents a "snapshot" in time and it can be instructive to compare the current snapshot to the last one. As discussed in Staff witness Dalton's testimony, for the Company's least-cost Plan A, the PLEXOS model results showed the NPV total system costs to be $34.7 billion,[14] which is $9.3 billion higher than the least-cost Plan A from the Company's Corrected 2018 IRP filing. This represents a 37% increase in costs for the least-cost plan from when the 2018 IRP was filed in May 2018 to when the current 2020 IRP was filed in May 2020. This change in PLEXOS model results is directly tied to the relatively significant changes to the commodity price forecasts from the 2018 IRP to the 2020 IRP.[15]

Such a dramatic swing in model results underscores the volatility and uncertainty of current markets. Further, a change in costs of 37% over such a short time span draws into question the level of accuracy of the Company's PLEXOS model results in this case, particularly when the Company refuses to perform any additional model runs and utilizes only one set of assumptions to model the future.

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[14] 2020 IRP at 32.

[15] Given that the Company forecasts for the 2020 IRP were completed prior to passage of the VCEA, these forecasts are already out of date.

Q18. DOES STAFF HAVE ANY RECOMMENDATIONS TO ADDRESS THIS LACK OF TRANSPARENCY IN FUTURE IRP FILINGS?

A18. Yes. Staff recommends that the Commission require the Company to perform numerous sensitivity analyses in future IRP filings. Further, any CPCN filings or any other cost recovery filings that rely on PLEXOS modeling should also include sensitivity analyses. PLEXOS model runs should be provided for high and low PJM energy prices, high and low PJM capacity prices, high and low construction costs, high and low fuel prices and any other scenarios the Commission deems necessary.

Staff further recommends that the Commission require the Company to provide all input files that are used in the PLEXOS modeling, or any other modeling software used by the Company, to Staff and any other party that requests this data in future IRPs, CPCNs, or any cost recovery filings where the Company used such software. This will add an additional layer of transparency by allowing Staff and other parties to inspect the reasonableness of the data that is input into the model. In addition, it would provide Staff and other parties an opportunity to hire a modeling consultant to independently verify the Company's model results.

<u>ISSUES WITH DEV'S MODELING OF ENERGY STORAGE</u>

Q19. WHAT ARE THE REQUIREMENTS CONTAINED IN THE VCEA FOR DEV RELATED TO ENERGY STORAGE?

A19. Subsection E of § 56-585.5 of the VCEA established an energy storage target of 2,700 MW for DEV by the year 2035. Importantly, the VCEA establishes this energy storage target to address system reliability stating:

> To enhance reliability and performance of the utility's generation and distribution system, each Phase I and Phase II Utility shall petition the Commission for necessary approvals to construct or acquire new, utility-owned energy storage resources.

Q20. WHAT ARE STAFF'S ISSUES WITH THE COMPANY'S MODELING OF ENERGY STORAGE RESOURCES?

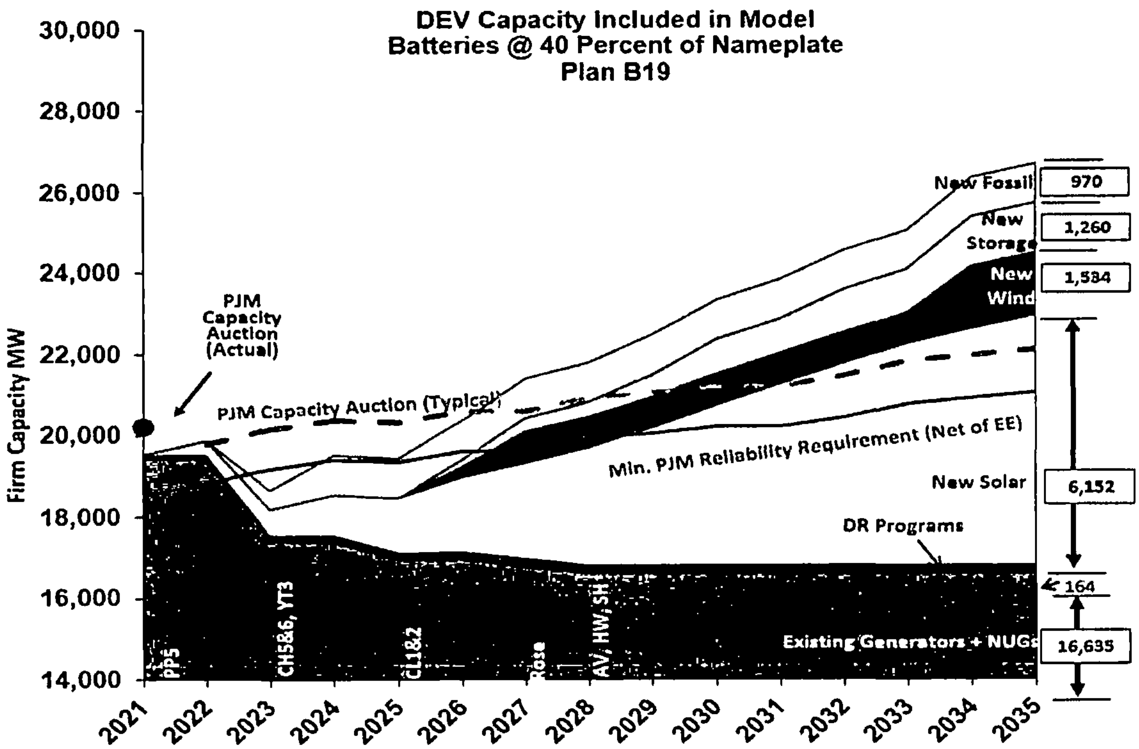
A20. Staff has three primary concerns about the Company's modeling of energy storage resources. These issues are: (i) the reduction of the nameplate capacity for battery storage resources input into the PLEXOS model; (ii) the Company's PJM energy price forecasts used in the model which do not reflect the impact of the Company's proposed build plan to comply with the requirements of the VCEA; and (iii) the Company's use of unrealistic values for battery storage resources in the PLEXOS model that are not consistent with the green sheets data. Staff believes that the Company's treatment of energy storage resources in the PLEXOS modeling is a significant deficiency in the 2020 IRP.

Q21. WHAT ARE STAFF'S CONCERNS WITH THE COMPANY'S REDUCTION OF THE NAMEPLATE CAPACITY OF BATTERY STORAGE RESOURCES IN THE PLEXOS MODEL RUNS?

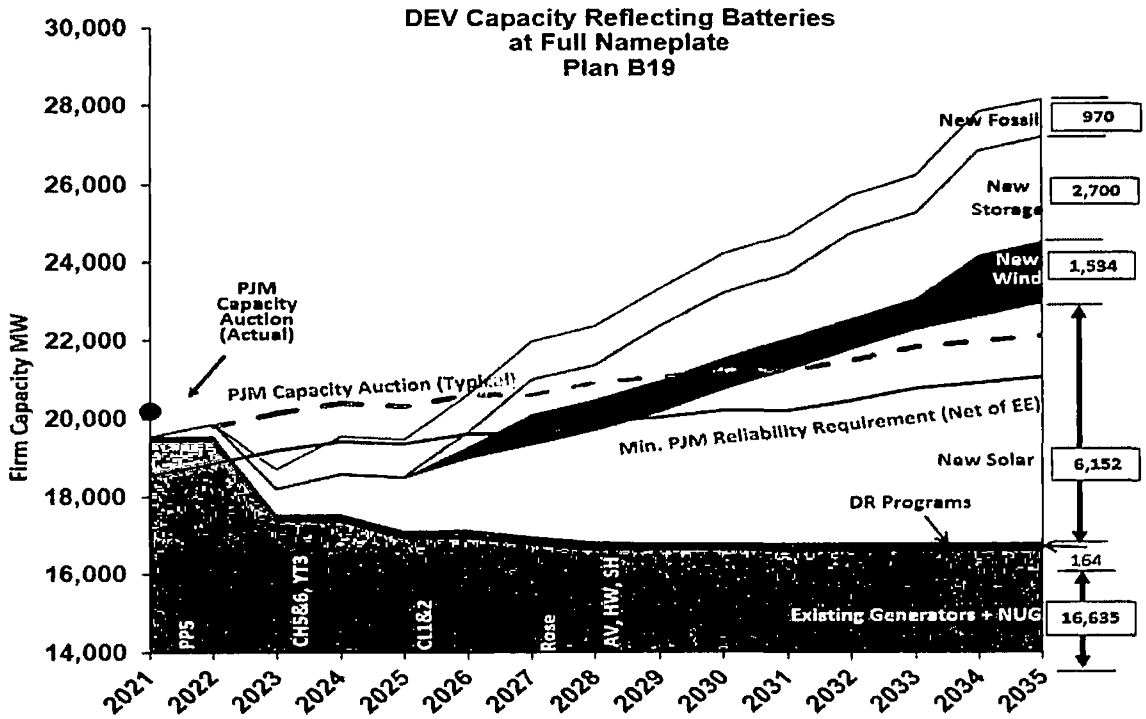
A21. As mentioned above, the energy storage requirements contained in the VCEA appear to be primarily aimed at maintaining system reliability of both the Company's generation and distribution systems. The PLEXOS model is an economic model. It is not a model that is designed to address system reliability issues. It appears to Staff that the Company reduced the nameplate capacity of battery storage resources by 60% to reflect how these resources may be paid as capacity resources in the PJM capacity market. In order to get full payment in the PJM capacity market, it is Staff's understanding that a resource must be able to dispatch continuously for 10 hours. Since DEV is modeling 4-hour batteries, it appears that the Company assumed that batteries would be paid for 40% of nameplate capacity.

Q22. DOES THAT MEAN THAT ONLY 40% OF THE NAMEPLATE CAPACITY WILL BE AVAILABLE DURING THE PJM COINCIDENT PEAK?

A22. No. Battery storage resources are fully dispatchable resources. The Company's reduction of the nameplate capacity available for serving the system peak is more consistent with how the Company treats a non-dispatchable intermittent resource. Given that battery storage resources are fully dispatchable and the PJM coincident peak is predictable, Staff believes that the full nameplate capacity of the batteries will be available at the time of the PJM coincident peak most of the time. PJM issues heat advisories during extreme weather events putting generators on notice that a peak event may occur the following day. The Company has a 4-hour operational window for the batteries to capture a 1-hour event that it knows is coming. Although it may be reasonable to reduce the capacity of the battery storage resources solely for the purposes of calculating capacity revenues in an economic model, it would be incorrect to reduce the *effective* capacity of the battery storage resources as being incapable of serving system peak load.[16] The charts below show the impact on the Company's capacity position reflecting the reduced capacity used by the Company versus the full nameplate capacity of battery storage resources.



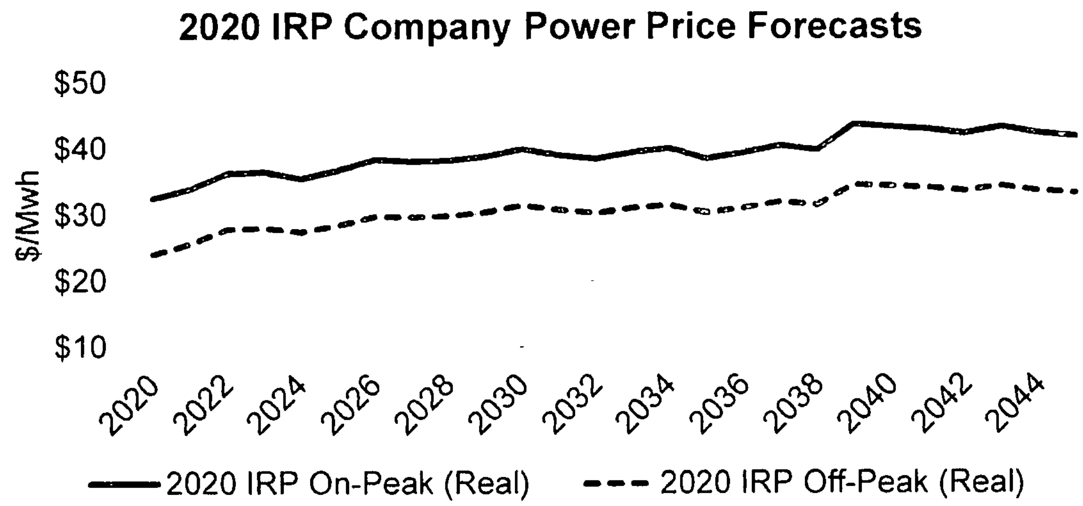
[16] It is unclear if the Company intends to bid the battery storage resources into the capacity market, however, Staff accepts the likelihood that the Company may only receive 40% of nameplate capacity revenues in the capacity market. However, whether the batteries are bid into the capacity market or not, Staff would expect the batteries to be bid into the PJM energy market during the PJM coincident peak given the relatively high energy price expected during the peak. If the batteries are dispatching at close to their full nameplate capacity at that time, then the batteries will essentially be acting as load reducers and will tend to decrease the Company's future load obligation in the capacity market.

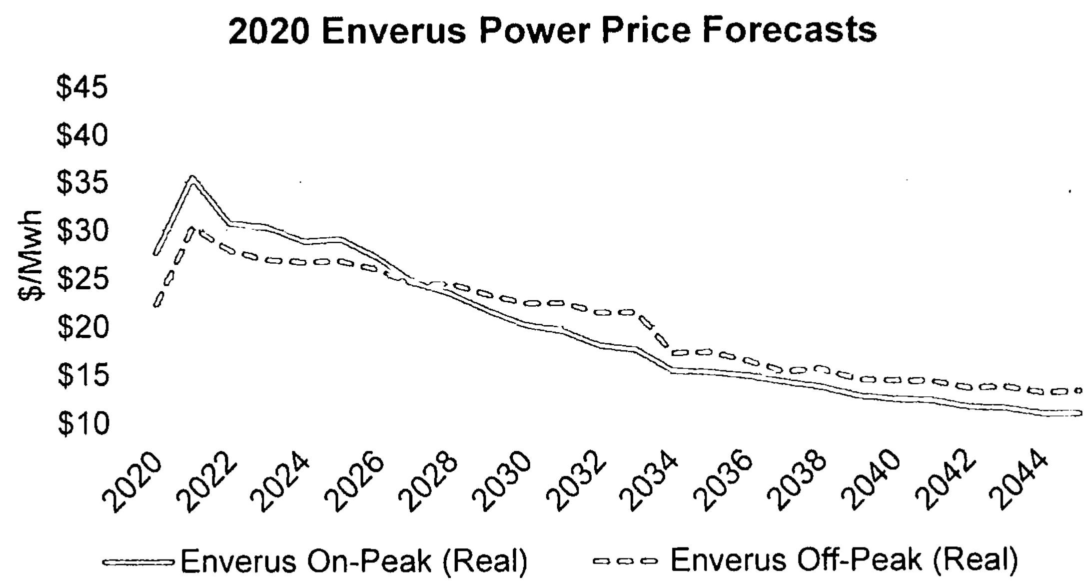


Q23. WHAT ARE STAFF'S CONCERNS WITH THE FORECAST OF FUTURE ENERGY PRICES ON THE MODELING OF ENERGY STORAGE RESOURCES?

A23. As discussed by Staff witnesses White and Johnson in their testimonies, the Company's forecast of PJM on-peak and off-peak energy prices were conducted in the fall of 2019. As a result, the Company's forecast did not capture the impacts on future PJM energy prices from the VCEA requirements for a substantial increase in intermittent resources, particularly additional solar resources. Staff's independent consultant performed a forecast of future PJM on-peak and off-peak energy prices that reflects the Company's build plan for VCEA-compliant Plan B_{19}. Staff's forecast shows that the large build out of intermittent resources required by the VCEA puts downward pressure on future PJM energy prices.

Of particular importance for energy storage resources, the large increase in solar resources applies substantially more downward pressure to on-peak PJM energy prices than off-peak energy prices. The charts below, prepared by Staff's consultant, compare the Company's PJM energy price forecast to Staff's forecast.





Q24. WHAT ARE THE IMPLICATIONS OF STAFF'S ENERGY PRICE FORECAST FOR THE MODELING OF ENERGY STORAGE RESOURCES?

A24. Both pumped storage and battery storage resources have a net round-trip loss of energy when the resources are dispatched. Pumped storage has a round-trip efficiency of about 80%. This means that for every 80 MWs of energy dispatched, 100 MWs of energy is consumed to recharge the reservoir. Similarly, the Company assumed that battery storage resources have a round-trip efficiency of about 85%.

Given this net loss of energy when energy storage resources are dispatched, for the dispatch to be economic, on-peak energy prices must be more than 15-20% higher than off-peak energy prices. As can be seen in the charts above, the Company maintains a differential between on-peak and off-peak energy prices through the study period. However, Staff's energy price forecast shows a steady erosion of the differential between on-peak and off-peak energy prices and introduces the possibility that the large increases in solar energy production required by the VCEA will result in future off-peak energy prices being higher than on-peak energy prices. This result would erase the economics of dispatching energy storage resources. It also suggests that when energy storage resources are dispatched for system reliability purposes, such dispatches will result in net costs rather than in net benefits. Consequently, given that the Company includes 5,114 MW to 9,914 MW of energy storage resources in the VCEA-compliant plans,[17] it

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[17] 2020 IRP at 5; May 14, 2020 Supplement at 1.

also suggests that the Company's NPV costs associated with the VCEA-compliant plans are understated.

Q25. DOES STAFF HAVE ANY FURTHER COMMENTS REGARDING THE COMPANY'S COMMODITY PRICE FORECASTS ON MODELING THE IRP?

A25. The Company's commodity price forecasts were completed before the passage of the VCEA and do not reflect the buildout envisioned by that legislation in solar, offshore wind resources and energy storage. These VCEA build plans will have a significant impact on future commodity prices. The failure to account for the VCEA on commodity price forecasts used as inputs into the IRP modeling is a deficiency of this IRP and, as such, the Company may not have fully complied with the Commission's March 9, 2020 Order that directed the Company to model the VCEA in the 2020 IRP.

Q26. MOVING TO YOUR NEXT CONCERN, WHY DOES STAFF TAKE ISSUE WITH HOW BATTERY STORAGE RESOURCES WERE INPUT INTO THE PLEXOS MODEL?

A26. Staff discovered an unexpected result in the model outputs reported in the 2020 IRP which raised questions regarding how the Company modeled battery storage resources compared to how the Company modeled the existing Bath County Pumped Storage units.

Q27. WHAT WAS THIS UNEXPECTED RESULT AND WHAT ARE STAFF'S CONCERNS?

A27. Specifically, Appendix 5D shows the expected net capacity factors for all generating units contained in Plan B for the period 2017 through 2035. Historically, the Bath County Pumped Storage units have had a net capacity factor of around 14-15%. It is notable that the Company's modeling results project the net capacity factor for the Bath County Pumped Storage units to steadily decrease over the planning period until it is cut in half in 2035 at 7.5%. This result was surprising to Staff given the apparent need for energy storage resources to balance out the intermittency of the large amounts of solar and offshore wind resources.

More troubling to Staff, however, are the projected net capacity factors for generic battery storage resources that the Company intends to construct in accordance with the VCEA. In 2035, the Company's PLEXOS modeling results show net capacity factors ranging from 14.6% to 15.1% for these generic battery storage resources, or about double the expected net capacity factor for the Bath County Pumped Storage units. Staff would have expected the net capacity factors for battery storage resources to be about the same as for pumped storage resources.

Q28. DID STAFF INVESTIGATE WHY THE PROJECTED NET CAPACITY FACTORS FOR BATTERIES ARE DOUBLE THE PROJECTED NET CAPACITY FACTORS FOR PUMPED STORAGE RESOURCES?

A28. Yes. Attachment GLA-1 contains the Company's response to Staff Interrogatory No. 18-172 which asked why the Company's PLEXOS model projected the new battery storage units would operate at double the capacity factor of the existing Bath County Pumped Storage units. The Company's response stated: "The higher capacity factor for new battery storage resources when compared to Bath County pump storage is likely tied to their modeled operating parameters." The response also provided a table of the modeled operating parameters. This table is reproduced below.

Storage Unit Parameters

	Bath County 1 (Dom Ownership)	Generic Battery
Max Capacity (MW)	301	30
Firm Capacity (MW)	301	12
Variable Cost ($/MWh)	0.155	0
Pump/Charge Efficiency	80%	85%
Maintenance Rate	7.39%	0
Recycle Period	Weekly	Daily
Duration	10hrs	4hrs

Based on the discovery response, the storage unit parameters contained in the above table are the actual inputs that went into the PLEXOS model runs performed for the 2020 IRP. Two of the parameters input into the model for battery storage resources appear to be unreasonable and are also contradicted by the information previously provided to Staff as the "Battery Storage Green Sheet."[18] Specifically, Staff believes it is unreasonable to input a variable cost of zero for battery storage resources and to, likewise, assume a maintenance rate of zero. Such assumptions are simply unrealistic.

Q29. HOW DO THE MODELED OPERATING PARAMETERS DIFFER FROM THE VALUES PROVIDED IN THE BATTERY STORAGE GREEN SHEET?

[18] The green sheet values for battery storage are the data used by the Company to produce the Busbar results contained in Appendix 5M of the 2020 IRP.

A29. The table below provides a modified version of the previous table to include the battery storage green sheet values.

CONFIDENTIAL INFORMATION REDACTED

Storage Unit Parameters

	Bath County 1 (Dom Ownership)	PLEXOS Generic Battery	Green Sheet Battery
Max Capacity (MW)	301	30	30
Firm Capacity (MW)	301	12	TBD
Variable Cost ($/MWh)	0.155	0	[redacted]
Pump/Charge Efficiency	80%	85%	N/A
Maintenance Rate	7.39%	0	14.1%
Recycle Period	Weekly	Daily	N/A
Duration	10hrs	4hrs	N/A

The Company provided the battery storage green sheet values in response to Staff Interrogatory No. 1-2. As can be seen in the table above, the green sheet values for variable costs and for maintenance rate contradict the values used in the PLEXOS modeling.

Q30. WHAT ARE THE IMPLICATIONS OF THIS DISCONNECT BETWEEN THE GREEN SHEET DATA AND THE PARAMETERS THAT WERE INPUT INTO THE MODEL?

A30. This disconnect between the green sheet data and the actual data used in the PLEXOS model was only uncovered because Staff observed an unusual model output. This disconnect emphasizes the black box nature of the Company's PLEXOS modeling performed in the 2020 IRP, as previously discussed. Further, it draws into question whether other green sheet data provided to Staff were not accurately reflected in the model. This further underscores Staff's earlier recommendation to require the Company to provide all input files that are used in the PLEXOS modeling, or any other modeling software used by the Company, to Staff and any other party that requests this data in future IRPs, CPCNs, or any cost recovery filings where the Company uses such software.

ISSUES WITH THE GENERATION UNIT RETIREMENT ANALYSIS

Q31. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S GENERATION UNITS RETIREMENT ANALYSIS?

A31. Yes. Staff witness Dalton discusses the Company's generation unit retirement analysis in his testimony. I have a few additional comments to add to his observations.

Q32. WHAT IS YOUR FIRST OBSERVATION?

A32. The Company evaluates Chesterfield units 5 and 6 together in the retirement analysis. Similarly, the Company evaluates Clover units 1 and 2 together in the retirement analysis. Staff recommends for any future generation unit retirement analysis that each individual unit be evaluated separately. Grouping units together could result in the retirement of a unit that is providing positive value to customers if it is grouped with a unit that is more negative. For example, if the continued operation of one unit is a positive \$100 million value to customers and this unit is lumped together with a second unit that has a negative \$120 million value, then taken together, the retirement analysis would call to retire both units to save ratepayers \$20 million. However, when looked at separately, only the second unit would retire and the ratepayers would realize \$120 million of positive benefits.

Q33. DO YOU HAVE COMMENTS ON THE COMPANY'S UNIT RETIREMENT RESULTS FOR VCHEC?

A33. Yes. The Company's retirement analysis shows that the continued operation of VCHEC through 2030 will cost customers $472 million over the next ten years. That is significantly higher than the NPV cost savings to customers from all other retiring units combined. To put this in perspective, this is over 22 times greater than Clover Units 1 and 2 which the Company show retiring in all plans, including the least-cost Plan A in 2025. Despite the results of the retirement analysis, all of the Company's plans show the continued operation of VCHEC throughout the 25-year study period in all plans.

Staff believes that if a utility performs a generation unit retirement analysis and that analysis shows that the correct economic decision calls for retiring a unit, and the utility instead chooses to ignore the analysis and run the uneconomic unit anyways, then the utility could be at risk of the Commission finding such a decision was imprudent in future cost recovery proceedings.

<u>IMPACT OF ENERGY EFFICIENCY ON CUSTOMER BILLS</u>

Q34. GIVEN THAT EE PROGRAMS ARE DESIGNED TO REDUCE CONSUMPTION, DOES STAFF'S TYPICAL BILL ANALYSIS REFLECT A LOWERING OF THE TYPICAL RESIDENTIAL BILL USAGE?

A34. No. Staff's typical residential bill analysis is contained in Staff witness Myers' testimony. The common frame of reference (i.e., benchmark) for evaluating typical monthly residential bills is to use 1,000 kWh to obtain an apples to apples comparison.[19] As long as the typical monthly bill analysis reflects both the costs of the EE programs and the benefits of those programs, Staff's analysis includes the impact on a typical monthly bill of 1,000 kWh associated with the implementation of the future EE programs included in the VCEA-compliant plans.

Q35. DID STAFF WITNESS MYERS INCLUDE IN STAFF'S TYPICAL RESIDENTIAL BILL ANALYSIS THE IMPACTS OF THE COMPANY'S FUTURE EE PROGRAMS CONTAINED IN THE IRP?

A35. Yes. Staff witness Myers included both the Company's estimated reductions in load (benefits) associated with the future EE programs and the estimated costs of the future EE programs in her bill analysis showing the projected monthly residential bill for a typical residential customer using 1,000 kWh per month.

Q36. SHOULDN'T STAFF'S TYPICAL BILL ANALYSIS SHOW A REDUCTION IN THE TOTAL TYPICAL MONTHLY BILL?

A36. Ideally, yes. It is possible that total bills could go down under a specific set of circumstances, however, it is not a foregone conclusion that this will happen, particularly in the case of a vertically integrated utility such as DEV.

Q37. WHAT IS THE SIGNIFICANCE OF DEV'S STATUS AS A VERTICALLY INTEGRATED UTILITY WITH REGARD TO EE PROGRAMS?

A37. Virginia is not a deregulated state and DEV is a vertically integrated utility that owns generation, transmission, and distribution resources. In deregulated states, the

[19] The actual average monthly residential bill in a given year is usually between 1,100 and 1,150 kWh, however, it is common practice to use 1,000 kWh.

local distribution companies ("LDCs") do not own generation resources. To the extent that EE programs are implemented in a deregulated state and, as a result, merchant generators produce less energy or go out of business, the LDC's customers do not incur any costs associated with these losses from the merchant plants.

In the case of DEV, the Company owns substantial generation resources with costs recovered from customers in base rates and through RACs. The Company has an opportunity to recover the capital costs, or revenue requirements, associated with these generation units irrespective of any energy reductions that may occur due to EE programs. For example, for Rider W, the Company recovers the annual revenue requirement from customers through a volumetric charge. The Rider W residential rate is calculated by dividing the revenue requirement by the total amount of energy sales to arrive at the $/kWh Rider W rate. If customers use 10% less energy as a result of EE programs, the exact same revenue requirement will still be recovered, however, it will now be recovered from 10% fewer billing units and the $/kWh rate for Rider W would go up by 10%, and customers would essentially pay the same amount on their monthly bills.

Q38. PLEASE EXPLAIN HOW EE PROGRAMS CAN LOWER BILLS FOR DEV'S CUSTOMERS.

A38. For a vertically integrated utility such as DEV, EE programs can result in customer savings in three ways. The first way, which is easier to see, is that customers will see a reduction in the fuel factor component of their bills. If customers use less energy in a given hour, the Company will either buy less energy from PJM in that hour or have more energy to sell into PJM during that hour. If an existing

Company-owned dispatchable generating unit is dispatched less, it will consume less fuel. All these effects will be reflected as a reduction in the fuel factor on the customer bill.

The second way EE programs can reduce future customer bills is not as easy to see. The implementation of EE programs should decrease both the total energy consumed over the planning period and DEV's peak load during the PJM coincident peak. Such a reduction in annual energy sales and peak loads can obviate the need for new Company-build generation units or postpone the timing of such investments. Unlike existing Company-owned generation units with costs already recovered through base rates or RACs, the customers will realize a savings on their future bills from the elimination of, or postponement of, these future generation resources.

The last way that EE programs can lower customer bills is by the lower energy sales that occur as a result also lowering the amount of renewable energy certificates ("RECs") required to meet the annual mandatory RPS requirements contained in the VCEA.[20] Lower annual RPS goals will reduce the need for new Company-build renewable resources, along with the associated future RACs, to meet the RPS goals. Alternatively, EE programs will also reduce the amount of RECs the Company must purchase from the REC market to meet any shortfall in satisfying the RPS goals or, alternatively, increase the amount of RECs the Company can sell into the REC market in years when DEV has a surplus of RECs.

[20] The VCEA establishes requirements as a percentage of total electric energy sold in the previous calendar year. Code § 56-585.5 C.

Q39. DID STAFF WITNESS MYERS CAPTURE THESE EFFECTS IN STAFF'S TYPICAL RESIDENTIAL BILL ANALYSIS?

A39. Yes, to the extent the Company captured them in its modeling. Staff's typical residential bill analysis reflects the PLEXOS model results for Plans B and B_{19}. The Company's modeling included the load reduction expected to be obtained from its future EE programs to achieve the VCEA EE goals. Thus, the PLEXOS model results reflect both the projected reduction in the fuel factor and the impact on the build plan to meet future peak loads. However, as discussed by Staff witness Dalton, a significant deficiency in the Company's modeling is that it did not adequately model the RPS requirements, especially by not applying excess RECs generated in certain earlier years (i.e., "banked" RECs) to RPS requirements in future years to optimize value for customers.

Q40. DID THE IMPLEMENTATION OF THE EE PROGRAMS RESULT IN LOWER TYPICAL MONTHLY RESIDENTIAL BILLS?

A40. As I stated earlier, EE programs for a vertically-integrated utility like DEV can lead to lower customer bills under a specific set of circumstances. A well-designed EE program, that is popular with customers, and that enjoys a high customer participation rate, can lead to *lower* customer bills if a utility currently has or is projected to have a capacity and/or energy deficit or a deficit in meeting RPS goals. Conversely, an EE program that is poorly designed, is not popular with customers and has a low participation rate, can lead to *higher* customer bills, especially if the utility currently has, or is projected to have, excess energy and capacity, or RECs in excess of future RPS goals.

In order to determine whether the proposed EE programs in the 2020 IRP would result in otherwise lower, or higher, customer bills, Staff Interrogatory No. 19-177 (a) requested that the Company perform two additional PLEXOS model runs for Plans B_{19} and D. Staff requested that the Company re-run the model removing both the costs of all unapproved EE programs and the associated projected peak load and energy reductions. Comparing the model results both with and without the EE programs would reveal whether the EE programs decrease or increase the NPV costs of each plan. The Company objected to Staff's request and refused to perform the model runs. The Company's response, however, did state the following: "While the Company has not performed any specific analyses, the Company believes that removing the generic block of EE programs may decrease the NPV."

Thus, the Company believes that implementation of the future EE programs will likely result in a net increase in the NPV costs of the plans and, consequently, to customer bills.

As discussed by Staff witness Dalton, the Company's proposed build plans for all VCEA-compliant Plans B through D add capacity and energy in excess of actual need and also provides substantially more RECs than needed to meet the RPS goals. Given this, Staff believes that the potential value of EE programs will be diminished. That is, the implementation of EE programs would simply lead to even higher excess capacity, energy, and REC positions.[21]

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[21] Staff notes that the Company includes several very expensive build options in all plans. If the implementation of EE programs allowed the Company to avoid building the second tranche of offshore wind, for example, it is possible and probably likely that the EE programs would lower customer bills in that scenario.

Staff filed a motion to compel regarding this discovery and the Hearing Examiner's ruling dated September 16, 2020 required the Company to provide the PLEXOS model runs requested in Staff Interrogatory No. 19-177 (a). As of the time this testimony was being finalized, however, Staff has not yet received these model results.

<u>**NEED FOR MORE TRANSPARENCY IN CUSTOMER BILLS**</u>

Q41. WHY DOES STAFF BELIEVE THAT THERE IS A NEED FOR GREATER TRANSPARENCY IN THE RENDERING OF CUSTOMER BILLS?

A41. As will be discussed in more detail below, the Company's current bill format is basically the same as it was prior to the 2007 Regulation Act. Given the major changes included in that law and other subsequent legislation discussed earlier in my testimony, Staff believes that the current bill format is stale, out of date, and may be inadequate for conveying relevant details concerning the calculation of the customers' bills.

Further, the Commission's June 27, 2019 Final Order in Case No. PUR-2018-00065 stated the following:

> A primary purpose of an IRP, however, is to give the public - which includes customers and the legislators who represent them - a reasonably accurate picture of the probable costs that customers will pay in the future to receive a reliable supply of electrical power, which is essential to modern life and commerce.

The Commission's March 9, 2020 Order in this proceeding, in addition to referencing the language above, directed the Company in the 2020 IRP to:

> Calculate separately the annual bill impacts of the least cost plan, the VCEA, and additional legislation over each of the

> next ten years as compared to the bill of a residential customer using 1,000 kilowatt-hours per month as of May 1, 2020, including not only generation costs but also transmission and distribution costs.

Although the Commission is specifically addressing IRPs above, Staff believes the same principle of transparency is applicable to the customer bills, especially in light of the potential proliferation of RACs that will likely flow to customers from implementation of the 2018 GTSA and the VCEA. Only a few engaged customers will read an IRP, but most customers read their bills.

Further, as is discussed further below, the Company's current billing format may no longer fully meet the requirements of 20 VAC 5-312-90 of the Commission's Retail Access Rules. In particular, the Commission may want to consider whether the Company's current bill format adequately complies with the Retail Access Rules in light of the expansion in the type and number of RACs that the Commission has approved pursuant to the 2007 Regulation Act and the additional RACs available pursuant to the 2018 GTSA and the VCEA.

Q42. HAS THE COMMISSION PREVIOUSLY ADDRESSED THIS ISSUE?

A42. Yes. Staff raised the issue of whether RACs should be disclosed to ratepayers as an individual line item on the bill in Case No. PUE-2009-00017 which established a RAC, designated Rider R, for cost recovery associated with the Bear Garden Generating Station pursuant to the 2007 Regulation Act.[22] Staff did not take a

[22] This was the second RAC approved pursuant to the 2007 Act. The first RAC approved pursuant to the 2007 Act was Rider S (Case No. PUE-2007-00066), for cost recovery associated with the Virginia City Hybrid Energy Center.

position on the proper billing format in that case but rather identified the issue for the Commission's consideration.

Q43. WHAT DID THE COMMISSION FIND REGARDING THIS ISSUE IN CASE NO. PUE-2009-00017?

A43. The Commission found, at that point in time, that the Company's current billing format met the requirements of 20 VAC 5-312-90 of the Commission's Rules.[23]

Q44. GIVEN THIS PRIOR COMMISSION GUIDANCE, WHY IS STAFF RAISING THIS ISSUE IN THE CURRENT CASE?

A44. When the Commission addressed this issue in Case No. PUE-2009-00017, only one other RAC (Rider S) had been approved under the 2007 Regulation Act and, with approval of Rider R, only two generation RACs would impact customer bills going forward. This has since changed dramatically as additional RAC opportunities have been created by the General Assembly[24] and additional RACs have been approved by the Commission pursuant to the 2007 Regulation Act and other subsequent legislation. The table below shows the RACs that currently flow through customers' bills:

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[23] *Application of Virginia Electric and Power Company, For Approval of a Rate Adjustment Clause for Recovery of the Costs of the Bear Garden Generating Station and Bear Garden-Bremo 230 kV Transmission Interconnection Line*, Case No. PUE-2009-00017, 2009 S.C.C. Ann. Rept. 416, 418, Order Approving Rate Adjustment Clause (Dec. 16, 2009).

[24] For example, in addition to the GTSA and the VCEA, the General Assembly created additional RAC opportunities for (i) new underground facilities to replace one or more existing overhead distribution facilities (2014); vegetation management (2015); certain solar facilities (2015); and pumped hydroelectricity generation and storage facilities (2017).

Distribution Service
Rider C1A – Peak-Shaving
Rider C2A – Energy Efficiency
Rider C3A – Energy Efficiency
Rider U – Strategic Underground Program

Electric Supply Service
Generation
Rider B – Biomass Conversions
Rider BW – Brunswick County Power Station
Rider E – Environmental Projects
Rider GV – Greensville County Power Station
Rider R – Bear Garden Generating Station
Rider S – Virginia City Hybrid Energy Center
Rider US-2 – Solar Projects
Rider US-3 – Solar Projects
Rider US-4 – Solar Projects
Rider W – Warren County Power Station

Transmission
Rider T1 – Transmission

RACs have also become a larger portion of the overall customer bill. For example, based on Staff witness Myers' typical bill analysis in May 2020, a typical residential customer using 1,000 kWh would receive a total monthly bill of \$116.18. Of this total, \$37.00, or 31.8%, recovers the various charges associated with the RACs identified above. Further, the RACs and the fuel factor combined amount to \$54.36, or 46.8% of the total bill. However, as will be discussed below, there is limited information on customer bills identifying or explaining these RAC-related charges.

Both the 2018 GTSA and the VCEA declare numerous generation resources and other investments to be in the public interest. Cost recovery for such resources are eligible to be recovered through RACs. It therefore seems likely that these provisions will cause an increase in the number of approved RACs. As such, Staff expects the percentage of the typical customer's total bill attributable to RACs to continue to increase. Based on Staff witness Myers' typical bill analysis, by 2030 the typical monthly residential bill will equal $183.50, and RACs and the fuel factor will account for $121.68, or 66.3%, of this $183.50 total. This is a substantial increase compared to the May 2020 monthly bill.

Given the large number of existing RACs and anticipated new RACs, Staff believes it may be appropriate to revisit the issue of whether sufficient information is being provided on customer bills regarding the Company's approved RACs.

Further, the Company's current billing format may not adequately comply with 20 VAC 5-312-90 I.1 of the Commission's Retail Access Rules.

Q45. PLEASE EXPLAIN FURTHER.

A45. 20 VAC 5-312-90 I.1 of the Retail Access Rules states:

> *Sufficient information shall be provided or referenced on the bill so that a customer can understand and calculate the billing charges.*

Q46. IS THERE ANY INFORMATION ON THE CUSTOMERS' BILLS THAT WOULD ALLOW CUSTOMERS TO CALCULATE, VERIFY AND UNDERSTAND THEIR BILLS?

A46. There is limited information on the customers' bills. A sample bill is provided below. As can be seen on the front of the bill, the customer's usage and usage history are displayed, but there are no actual rates on the bill that would enable the customer to verify his bill. The total bill amount owed is broken down by "Distribution Service" and "Electric Supply Service" which is further broken down to "Generation," "Transmission" and "Fuel." Lastly, the various applicable taxes are shown as line items on the bill. However, there is no information on the front of the bill regarding the various RACs even though the RAC charges are included in the billing amounts. There is a reference to a web address that provides more details on how bills are calculated. This reference on the bill could be viewed as minimally complying with the Rules.

Sep 03, 2020 *Customer Bill* **Dominion Energy**

[redacted] [redacted]

Due to the coronavirus, we have suspended all disconnects for non-payment and late payment charges until further notice. If you have fallen behind on your bill, please contact us for payment arrangement options. We are here to help. Please visit DominionEnergy.com or call us at 1-866-366-4357.

Billing and Payment Summary

Account # [redacted] Due Date: Sep 28, 2020

Total Amount Due: $ 150.83

To avoid a Late Payment Charge of 1.5% please pay by Sep 28, 2020.

Previous Amount Due:	$	189.83
Payments as of Sep 03:	$	189.83CR

For service emergencies and power outages please call 1-866-DOM-HELP (1-866-366-4357). Visit us at www.dominionenergy.com.

Meter and Usage

Current Billing Days: 29

Billable Usage	
Schedule 1	*08/03-09/01*
Total kWh	1220
Measured Usage	
Meter: 0105061070	*08/03-09/01*
Current Reading	97105
Previous Reading	95885
Total kWh	1220

Usage History

Mo	Yr	kWh
Sep	19	1282
Oct	19	1121
Nov	19	673
Dec	19	1508
Jan	20	1812
Feb	20	1658
Mar	20	1474
Apr	20	952
May	20	997
Jun	20	860
Jul	20	1086
Aug	20	1534
Sep	20	1220

Explanation of Bill Detail

Customer Service 1-866-DOM-HELP *(1-866-366-4357)*

Previous Balance	189.83	
Payment Received	189.83CR	
Balance Forward		**0.00**
Residential (Schedule 1)		*08/03-09/01*
Distribution Service		31.57
Electricity Supply Svc (ESS)		
Generation		70.14
Transmission		24.08
Fuel		20.76
Sales and Use Surcharge		0.38
State/Local Consumption Tax		1.90
CHESTERFIELD Utility Tax		2.00
Total Current Charges		**150.83**
Total Account Balance		**150.83**

To better understand how your bill is calculated, visit www.dominionenergy.com/yourbill.

***** PRINT SUPPRESSED *****

Please detach and return this payment coupon with your check made payable to Dominion Energy Virginia. Please see reverse side for mailing address change instructions.

Payment Coupon

Bill Date Sep 03 20
Please Pay by 09/28
$ 150.83

Amount Enclosed

Account No. [redacted]

[redacted]

Send Payment to:

DOMINION ENERGY VIRGINIA
P O BOX 26543
RICHMOND VA 23290-0001

Q47. DOES THE COMPANY'S WEBSITE CONTAIN INFORMATION THAT WOULD ALLOW CUSTOMERS TO CALCULATE AND VERIFY THEIR BILLS?

A47. Yes, if customers follow the link provided on their bill, it takes them to a web page with the heading "Understand Your Bill," the customers can then find a link labeled "Bill Calculator Worksheet" that links to an interactive Excel spreadsheet. The customer can use this interactive spreadsheet to verify the charges on his/her bill by entering the usage information, the number of days in the billing cycle, and the applicable month from the bill. Entering the usage information into the bill calculator yields detailed information showing all applicable RACs and other bill components that comprise the monthly bill. Entering the information from the sample bill above into the Bill Calculator Worksheet provides the following detailed breakdown of the sample bill.[25]

[25] The bill components and total bill for the detailed bill does not exactly match the bill total for the sample bill because several RACs changed effective September 1, 2020.

Schedule 1 - Virginia Residential Service Rate Worksheet

Refer to effective dates listed in left hand column.

Dominion Energy Virginia is providing this Rate Worksheet to its Virginia residential customers as a tool to help in better understanding their Schedule 1 - Residential Service electric bill. This Rate Worksheet is only a guide, and Dominion Energy Virginia is not responsible for any errors resulting from its use. For example, rounding differences may occur between the charges listed on your electric bill itself and this worksheet. If there is a discrepancy, the Customer Bill governs. Please refer to the Customer Bill for the actual charges.

NOTE: The basic customer charge and kWh tiers are prorated when the number of billing days is < 26 or > 40 days. The rates per kWh are prorated when the measured usage period spans over two rate filing dates. If one or more of these conditions exist, this worksheet may not accurately calculate the charges on your bill. In certain instances, when your bill date falls on the last few business days of either May or September or the first few business days of either June or October, the current reading date may be used to determine the billing month.

Required fields.

Billing Month:	June - Septembe
Current Billing Days:	29
Total kWh:	1,220

Using your bill, complete all of the required fields on the left; then scroll down to view the calculations.

	kWh	@	Rate per kWh		Subtotal	Charges
A. Distribution Service Charges						
1. Basic Customer Charge	n/a	@	flat charge	=	$ 6.58	
2. Distribution kWh Charge						
First 800 kWh	800	@	$ 0.021086	=	$ 16.87	
Over 800 kWh	420	@	$ 0.011943	=	$ 5.02	
3. Applicable Rider(s)						
Rider U (Strategic Underground Program)	1,220	@	$ 0.0014030		$ 1.71	
Rider C1A (Peak Shaving)	1,220	@	$ 0.0000560		$ 0.07	
Rider C2A (Energy Efficiency)	1,220	@	$ 0.0001760		$ 0.21	
Rider C3A (Energy Efficiency)	1,220	@	$ 0.0012300		$ 1.50	
					Distribution Service	$ 31.96

	kWh	@	Rate per kWh		Subtotal	Charges
B. Electricity Supply Service Charges						
1. Generation						
First 800 kWh	800	@	$ 0.0358260	=	$ 28.66	
Over 800 kWh	420	@	$ 0.0545000	=	$ 22.89	
2. Applicable Rider(s)						
Rider S (Virginia City Hybrid Energy Center)	1,220	@	$ 0.0038380	=	$ 4.68	
Rider B (Biomass Conversions)	1,220	@	$ 0.0006300	=	$ 0.77	
Rider W (Warren County Power Station)	1,220	@	$ 0.0020840	=	$ 2.54	
Rider R (Bear Garden Generating Station)	1,220	@	$ 0.0008770	=	$ 1.07	
Rider GV (Greensville Power Station)	1,220	@	$ 0.0026010	=	$ 3.17	
Rider BW (Brunswick County Power Station)	1,220	@	$ 0.0019470	=	$ 2.38	
Rider E (Environmental Projects)	1,220	@	$ 0.0019860	=	$ 2.42	
Rider US-2 (Solar Projects)	1,220	@	$ 0.0001880	=	$ 0.23	
Rider US-3 (Solar Projects)	1,220	@	$ 0.0005590	=	$ 0.68	
Rider US-4 (Solar Projects)	1,220	@	$ 0.0001470	=	$ 0.18	
					Generation	$ 69.67

	kWh	@	Rate per kWh		Subtotal	Charges
Transmission						
Transmission kWh Chg	1,220	@	$ 0.00970	=	$ 11.83	
Rider T1 (Transmission)	1,220	@	0.010591		$ 12.92	
					Transmission	$ 24.76

	kWh	@	Rate per kWh		Subtotal	Charges
Fuel						
Rider A (Fuel Charge Rider)	1,220	@	$ 0.017021	=	$ 20.77	
					Fuel	$ 20.77

	kWh	@	Rate per kWh		Subtotal	Charges
Sales and Use Surcharge	1,220	@	$ 0.00031	=	$ 0.38	
					Sales and Use Surcharge	$ 0.38

	kWh	@	Rate per kWh		Subtotal	Charges
Consumption Tax						
0 to 2,500 kWh						
State Consumption	1,220	@	$ 0.00102	=	$ 1.24	
Special Regulatory	1,220	@	$ 0.00015	=	$ 0.18	
Local Consumption	1,220	@	$ 0.00038	=	$ 0.46	
					$ 1.88	
2,501 to 50,000 kWh						
State Consumption	0	@	$ 0.00065	=	$ -	
Special Regulatory	0	@	$ 0.00010	=	$ -	
Local Consumption	0	@	$ 0.00024	=	$ -	
					$ -	
Over 50,000 kWh						
State Consumption	0	@	$ 0.00050	=	$ -	
Special Regulatory	0	@	$ 0.00007	=	$ -	
Local Consumption	0	@	$ 0.00018	=	$ -	
					$ -	
					State/Local Consumption Tax	$ 1.88

SUBTOTAL $ 149.42

Q48. DO YOU HAVE ANY COMMENTS ON THE DESIGN OF THE BILL CALCULATOR WORKSHEET?

A48. Yes. This Excel worksheet is excellent. It contains the complete details of the various components of the bill and is laid out in a logical, easy to understand format.

Q49. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE COMPANY'S BILL CALCULATOR WORKSHEET?

A49. Yes. Staff notes that not all of the Company's customers use the internet, particularly elderly and low-income customers. Further, not all customers who have access to the internet possess the Excel software required for customers to access the Company's Bill Calculator Worksheet.

Q50. DO YOU HAVE ANY FURTHER COMMENTS ON WHY STAFF BELIEVES IT IS APPROPRIATE TO RAISE THIS ISSUE NOW?

A50. Yes. The primary way the Company communicates with its customers is through the customer bill. Given that the likelihood that significant costs of the VCEA investments will be recovered through RACs, providing this detail on the bill will provide proof to customers that DEV is pursuing the VCEA goals and moving Virginia towards 100% clean energy. Currently, all RACs are hidden from customers on their bills. Staff believes that providing the detailed breakdown on customer bills will allow the customers to see this progress in real time. For example, customers would see a separate offshore wind RAC once the Company seeks approval for the first tranche of offshore wind.[26] Customers would also likely see a dramatic increase in solar RACs as the Company seeks approval of 16,100 MW of solar and onshore wind facilities. Conversely, as the various fossil fuel units are paid down or retired, customers would see fossil fuel RACs decreasing on their bills. As renewable energy RACs increase on the customer bill and fossil fuel RACs diminish, customers and legislators will be able to see in their bills that the

[26] Staff notes that the VCEA exempts certain low-income customers from paying the RAC for cost recovery of offshore wind. As such, Staff believes the Commission may want to consider requiring the offshore wind RAC to be a line item on the bill along with a message on the bill informing customers that certain low-income customers are exempt and providing a phone number for customers to call to see if they are eligible for the exemption.

Company's implementation of the VCEA is moving the Commonwealth towards 100% clean energy.

Q51. IS STAFF MAKING ANY FIRM RECOMMENDATION ON CUSTOMER BILL FORMATTING IN THIS PROCEEDING?

A51. No. Staff is merely raising the issue in this proceeding. Given the number of existing RACs and the number of future RACs expected under the VCEA, providing this much detail on customer bills could be difficult to accomplish. If the Commission finds that the current bill format is insufficient or that potential changes to the current bill format should be explored further, Staff recommends that the Commission direct the Company to propose alternative bill format proposals in its upcoming triennial review. Potential options could range from: (i) providing all details from the Company's Bill Calculator Worksheet in each customer's unique monthly bill;[27] to (ii) combining RACs into logical subgroups such as fossil fuel RACs, solar RACs, offshore wind RAC, etc. for display on the monthly bill; to (iii) leaving the monthly bills as they are currently but providing each customer an annual breakdown of his/her annual charges in the same level of detail and format as the Company's Bill Calculator Worksheet.

Q52. DOES THIS CONCLUDE YOUR TESTIMONY?

A52. Yes.

[27] This could result in a bill comprised of several pages.

ATTACHMENT GLA-1

Virginia Electric and Power Company
Case No. PUR-2020-00035
Virginia State Corporation Commission Staff
Staff Set 18

The following response to Question No. 172 of the Eighteenth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on August 7, 2020, was prepared by or under the supervision of:

Kevin Cross
Energy Market Consultant
Dominion Energy Services Inc.

Question No. 172

Please reference Appendix 5D showing the Net Capacity Factor for Plan B and Appendix 5U showing the Net Capacity Factor for Plan B_{19} for each generating unit for the period 2017 through 2035. Please explain why the Company is projecting that new battery storage units will operate at double the capacity factor of Bath County 1-6. Why would these energy storage resources not have roughly the same capacity factors?

Response:

The higher capacity factor for new battery storage resources when compared to Bath County pump storage is likely tied to their modeled operating parameters. Please see the modeled operating parameters in the table below.

Storage Unit Parameters

	Bath County 1 (Dom Ownership)	Generic Battery
Max Capacity (MW)	301	30
Firm Capacity (MW)	301	12
Variable Cost ($/MWh)	0.155	0
Pump/Charge Efficiency	80%	85%
Maintenance Rate	7.39%	0
Recycle Period	Weekly	Daily
Duration	10hrs	4hrs