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July 16, 2025

VIA ELECTRONIC FILING

Mr. Bernard Logan, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street
Richmond, VA 23218

Re: *Application of Virginia Electric and Power Company, for a 2025 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*
Case No. PUR-2025-00058

Dear Mr. Logan:

Please find the attached *Direct Testimony of Gregory Abbott,* filed on behalf of the Piedmont Environmental Council in the above matter.

Should you have any questions about this filing, please do not hesitate to contact me.

Sincerely,

/s/ William T. Reisinger

William T. Reisinger

cc: Certificate of Service (via email)
Office of Hearing Examiners (via email)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY	)))	
For a 2025 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia	))))	Case No. PUR-2025-00058

PREFILED DIRECT TESTIMONY

OF

GREGORY ABBOTT

ON BEHALF OF

PIEDMONT ENVIRONMENTAL COUNCIL

July 16, 2025

Summary of the Direct Testimony of Gregory Abbott

My testimony examines the application of Virginia Electric and Power Company ("Dominion" or "Company") for a biennial review of the Company's rates, terms, and conditions for the provision of generation, transmission, and distribution services.

This is a case of first impression. This is the first opportunity for the Commission to wrestle with cost allocation, rate design and terms and conditions in a very new and immersive environment due to the scope and scale of one group of energy users driving the size and design of the generation and transmission systems. Piedmont Environmental Council ("PEC") believes that we are entering into a new and different environment that requires a new and different approach than the old model.

My testimony addresses Dominion's proposal to establish a new GS-5 rate class for High Load customers in reaction to the recent and projected expansion of large-use hyperscale data centers in the Company's service territory. My testimony discusses whether the proposed terms and conditions for these large-use customers adequately and equitably shield non-data center customers from the risks and incremental costs of Dominion's proposed build plan to serve projected data center load contained in Dominion's 2024 IRP.

Further, my testimony examines Dominion's Class Cost of Service methodology and whether any changes to the current methodology are warranted given the projected size and scope of large-use hyperscale data centers driving Dominion's load forecast and the extent of the required new infrastructure required to serve this new load.

Lastly, my testimony discusses Dominion's proposal to move the recovery of capacity costs out of base rates and into the Company's fuel factor.

The table below summarizes PEC's recommendations for proposed GS-5 High Load customers and for capacity cost recovery compared to Dominion's proposal for each issue.

Issue	Dominion Proposed	PEC Recommendation
Minimum Charges	85% of Trans. and Dist. Demand Charges 60% of Generation Demand Charges	90% of Trans. and Dist. Demand Charges 90% of Generation Demand Charges
Reassignment of Capacity	20% Reduction at Customer Discretion 30% Reduction at Dominion's Discretion	10% Reduction at Customer Discretion 30% Reduction at Dominion's Discretion Require Dominion to Notify Commission of any Reductions to High Load Customers' Contract Capacity.
Contract Term	14 Years Total With a 4-Year Ramp Period	20 Years Total With a 3-Year Ramp Period
Ramp Rate	20% Per Year	40% Year 1, then 20% Per Year
Line Extension / Direct Assignment	N/A	Direct Assignment of Supplemental Transmission Project(s) to High Load Customer(s) Require Dominion to Propose and Submit a Tranmission Line Extension Policy for Commission Approval
Class Cost of Service	No Change in Current Methodology Proposed GS-5 Class to Track Cost Causation in the Future	No Change in Current Methodology for Dist. And Trans. Change to Probability of Dispatch ("POD") for Generation Transition to POD Over Next Three Biennial Reviews
Recovery of Capacity Costs	Move Recovery of Capacity Costs from Base Rates Into Fuel Factor. Allocate Capacity Costs using the A&E Methodology	Move Recovery of Capacity Costs from Base Rates Into Fuel Factor. Allocate Capacity Costs Using the Fuel Factor Energy Allocator

Q1. PLEASE STATE YOUR NAME AND ADDRESS AND YOUR ROLE WITH PIEDMONT ENVIRONMENTAL COUNCIL.

A1. My name is Gregory Abbott, and my address is 8610 Sunview Lane, North Chesterfield, VA. My expert testimony in this proceeding is on behalf of the Piedmont Environmental Council ("PEC").

Q2. PLEASE SUMMARIZE YOUR EXPERIENCE IN ELECTRIC UTILITY REGULATION IN VIRGINIA.

A2. I was previously employed as a member of the Virginia State Corporation Commission ("Commission") Staff and retired in 2022 as a Deputy Director after 24 years of service in the Commission's Division of Public Utility Regulation. Post retirement, I began working as an independent consultant and expert witness. I have widespread experience in the regulation of electric, gas, water, and sewer utilities located in the Commonwealth. This experience ranges from general rate increase applications, class cost of service, rate design, Integrated Resource Plans ("IRPs"), generation certificates of public convenience and necessity ("CPCNs"), Renewable Portfolio Standard ("RPS") cases, coal ash disposal, rate adjustment clauses ("RACs"), Demand-Side Management, PJM matters, weather normalization adjustments, Natural Gas Conservation and Ratemaking Efficiency Act ("CARE") plans, and pole attachments.

I have testified before the Commission in scores of cases and a representative list of cases is provided in Attachment GLA-1.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A3. My testimony examines the application of Virginia Electric and Power Company ("Dominion" or "Company") for a biennial review of the Company's rates, terms, and conditions for the provision of generation, transmission, and distribution services. More specifically, my testimony addresses Dominion's proposal to establish a new GS-5 rate class for High Load customers in reaction to the recent and projected expansion of large-use hyperscale data centers in the Company's service territory. My testimony discusses whether the proposed terms and conditions for these large-use customers adequately and equitably shield non-data center customers from the risks and incremental costs of Dominion's proposed build plan to serve projected data center load contained in Dominion's 2024 IRP.

Further, my testimony examines Dominion's Class Cost of Service ("CCOS") methodology and whether any changes to the current methodology are warranted given the projected size and scope of large-use hyperscale data centers driving Dominion's load forecast and the extent of the required new infrastructure required to serve this new load.

My testimony also discusses Dominion's proposal to move the recovery of capacity costs out of base rates and into the Company's fuel factor.

OVERVIEW

Q4. WHY IS THIS CASE IMPORTANT?

A4. This is the first opportunity for the Commission to wrestle with cost allocation, rate design and terms and conditions in a very new and immersive environment due to the scope and scale of one group of energy users driving the size and design of the generation and transmission systems. PEC believes that we are entering into a new and different environment that requires a new and different approach than the old model. Dominion's 2024 IRP filed on October 15, 2024 in Case No. PUR-2024-00184 ("2024 IRP Case") forecasted an incremental increase of 8 GW of data center peak load by 2039. However, on February 12, 2025, just four months later, Dominion held its Fourth Quarter earnings call and told shareholders that it has 40 GW of data center capacity in various stages of contracting as of December 2024.[1] This is a quintupling of the projected data center load modeled in Dominion's 2024 IRP mere months after the 2024 IRP was filed. If all of the 40 GW of new data center demand comes to fruition, this would more than triple Dominion's 2024 Coincident Peak Load for the entire system.

Q5. PLEASE PROVIDE AN OVERVIEW OF THE EVOLUTION OF DATA CENTER LOAD GROWTH.

A5. Modern data centers are a relatively new type of customer. At the start of the 21st century, the term "data center" was synonymous with on-premises computer rooms. In the mid-2000s, however, Amazon and Google launched public cloud services. Microsoft followed in 2010. This allowed many businesses to transfer the functions performed at their on-premises computer rooms to the cloud, providing a more efficient and lower cost computing and storage solution. Although data centers began developing in the early 2000s, they were not a significant source of load growth for Dominion until recent years. The table on page 5 of Dominion witness Blackwell's direct testimony provides relevant data center metrics. In 2013, Dominion served 29 data center customers with a combined demand of 462 MW, or about 16 MW per data center customer. By 2024, this had grown to 51 data center customers with a combined demand of 3,583 MW, or about 70 MW per data center customer. Further, on page 5 of Dominion witness Blackwell's direct testimony, he states: "Today, the majority of requests are for 300 MW campuses. However, the

[1] *Dominion Energy nearly doubles data center capacity under contract to 40GW*, available at https://www.datacenterdynamics.com/en/news/dominion-energy-nearly-doubles-data-center-capacity-under-contract-to-40gw/

Company has also received very large campus requests within the 2,400 to 7,000 MW range." This rapid escalation in the number and size of data center campuses reflects the evolution of the data center industry as it moves beyond cloud computing into new artificial intelligence ("AI") data center campuses. Indeed, PJM's data center load forecast shows explosive growth for many years into the future primarily concentrated in Virginia. This represents the greatest new demand for electricity since the invention and wide-spread adoption of air conditioning. The main difference being that electricity demand for air conditioning increased load for all customers and across all customer classes whereas the increased electricity demand to serve data centers is comprised of just a handful of some of the largest and wealthiest corporations in the world.

Q6. WHAT ARE THE IMPLICATIONS OF THIS DEVELOPMENT FOR THE CURRENT CASE?

A6. Dominion's proposal to establish a new GS-5 rate class for High Load customers allows for more accurate tracking of the demands and costs placed on the system to serve large-use hyperscale data centers. The new terms and conditions are being proposed to manage the concomitant risks that comes with rapid data center load growth. Forecasted load growth is the main driver of the proposed build plans developed in Dominion's IRPs. These IRP build plans are then used by Dominion as a blueprint for developing CPCN proposals for new generation resources. Further, Dominion's data center load forecast is also a main driver of the transmission infrastructure identified in recent PJM Regional Transmission Expansion Plans ("RTEP"). This in turn, manifests as CPCN requests by Dominion for new transmission infrastructure projects. The costs of the new generation and transmission infrastructure is recovered from customers through an array of cost recovery mechanisms including base rates and numerous RACs. Therefore, it is not possible to fully discuss the implications of data center load growth by limiting the discussion to just this biennial review.

This is Dominion's first proposal to respond to the issues raised by serving this new type of customer including the forecasted load, the costs of the required infrastructure improvements to serve this load, and the potential risks to existing customers associated with this growth. These issues cut across many different types of cases including this biennial review, IRPs, CPCNs for generation and transmission facilities, and RACs.

Given the above, it is PEC's position that the Commission should treat this as a case of first impression.

BACKGROUND

Q7. PLEASE DISCUSS RECENT DEVELOPMENTS THAT MAY HAVE SPURRED DOMINION'S PROPOSAL FOR A NEW GS-5 RATE CLASS TO SERVE HIGH LOAD CUSTOMERS.

A7. In its October 2, 2024 Scheduling Order in Case No. PUR-2024-00144, the Commission scheduled a Technical Conference to be held on December 16, 2024 for the express purpose of considering issues surrounding electric utilities and data center load growth.

In addition to the Commission's Technical Conference, the Joint Legislative Audit and Review Commission ("JLARC") conducted a thorough and comprehensive Data Center Study ("JLARC Study") and documented its findings in a Report transmitted to the Governor and the General Assembly of Virginia on December 9, 2024.[2]

[2] The JLARC Study, including the report of JLARC's consultant, E3, is available online at https://jlarc.virginia.gov/landing-2024-data-centers-in-virginia.asp

Lastly, several other states with data center footprints that are far smaller than Virginia are considering similar proposals to manage the costs and risks attendant to the expected rapid load growth caused by large-use hyperscale data centers.

Given Virginia's position as the largest data center market in the world, PJM's data center load forecast for the Dominion Zone ("DOM Zone"), and the recent developments outlined above, Dominion has proactively made a proposal in this case to address the cost allocation and risks associated with this rapid data center load growth.

RELEVANT COMMISSION ORDERS

Q8. DID THE COMMISSION DELINEATE SPECIFIC AREAS OF FOCUS FOR THE DECEMBER TECHNICAL CONFERENCE?

A8. Yes. The Commission scheduled the Technical Conference to explore the current and projected future challenges for serving large-use hyperscale data centers. On page 2 of the Scheduling Order, the Commission states the following:

> This proceeding is also aimed at exploring the identification of one or more potential frameworks that could be used by electric cooperatives and IOUs to serve potential new large-use customer load. In particular, the Commission is interested in potential frameworks that would facilitate service in a manner that, among other things, reasonably addresses the ***risks*** and issues attendant to this new load type, ***is just and reasonable to both current and future customers***, and is permissible under current Virginia statutory law. In addition, this proceeding may examine, to the extent relevant, issues related to the co-location of generation resources at new large-use customer load sites. Specific topics for discussion may include:
>
> 1. Whether the Commission should establish, on a going-forward basis, a tariff framework applicable to these large-use customers and the specific terms of service that it should include, such as:
>
>   a. Appropriate minimum bill amounts;
>   b. A line extension policy;

> c. Security and collateral provisions to protect against customer bankruptcy or other failure to meet financial commitments;
> d. Service contract term lengths;
> e. Exit fees; and
> f. Service terms during emergencies.
>
> 2. Whether certain transmission costs should be directly assigned to a new large-use customer class; and
>
> 3. Whether certain generation costs should be directly assigned to a new large-use customer class. (emphasis added)

Q9. HAS THE COMMISSION ISSUED ANY OTHER ORDERS THAT HAVE A BEARING ON THE COSTS AND RISKS POSED BY LARGE-USE DATA CENTER LOAD GROWTH?

A9. Yes. On October 11, 2024, the Commission issued an Order that docketed Dominion's 2024 IRP Case and directed Dominion to conduct certain modeling sensitivities that remove the projected data center load growth for Dominion's least cost plan and for at least one of its VCEA[3]-compliant plans. Specifically, the Commission Order directed the following:

> The Commission finds that Dominion should be required to conduct additional modeling that presents, as a sensitivity for comparison purposes to the Company's modeling presented in its 2024 IRP, the following: (i) its least cost plan, and (ii) at least one VCEA-compliant plan, both with projected data center load growth removed.

In addition, the Commission Order directed Dominion to provide certain transmission cost information as stated below:

> Lastly, in regards to transmission interconnection costs, the Company is currently required to "[p]rovide, in addition to a list of planned transmission projects, the projected cost per transmission project and indicate whether or not each project is subject to PJM's Transmission Expansion Planning process." For each of these

[3] Virginia Clean Economy Act.

> planned transmission projects, the Company shall also ***identify whether the need for the transmission project is primarily being driven by data center load growth***. The Commission notes that the Company provided this information in the 2023 Integrated Resource Plan in Appendix 3C. For purposes of complying with this requirement, the Company may simply add a column to this table to ***identify whether the primary need driver for the project is data center growth***. Such information shall be filed as a supplement to the 2024 Plan by November 15, 2024. (emphasis added) (Footnotes omitted)

Taken together, the recent Commission Orders scheduling the Technical Conference and requiring a supplemental 2024 IRP filing indicates that the Commission is keenly aware of the challenges that unfettered load growth of large-use hyper-scale data centers in Virginia present to the provision of reliable electric service at just and reasonable rates to Virginia's citizens. These Commission Orders provided a strong signal to Dominion to proactively get out in front of these challenges.

<u>JLARC STUDY</u>

Q10. HAVE YOU REVIEWED THE JLARC STUDY?

A10. Yes. I have reviewed the JLARC Study along with the report of its consultant – Energy + Environmental Economics ("E3"). Overall, I found the JLARC Study to be a thorough and unbiased examination of the issues and challenges presented by large-use hyperscale data center growth in Virginia. This is impressive given that JLARC is not normally emmeshed in the complexities of electric utility generation and transmission infrastructure planning, cost allocation, and rate design. With that said, however, it is important to keep in mind what the JLARC Study is and what it is not. The conclusions and findings contained in the JLARC Study cannot substitute for or override a finding of fact by the Commission after examining the evidence provided under oath and subject to cross examination. Neither JLARC nor E3 are participants in this case. Therefore, the assumptions, analysis, and conclusions contained in the JLARC Study cannot be explored through cross-examination in this case. Nevertheless, I believe the JLARC Study provides an important neutral data point for the Commission to consider in the current case.

Lastly, with all due respect to JLARC, the Commission is the state agency that oversees the regulation of electric utilities in Virginia and the experts on the Commission's Staff have a deep knowledge and extensive experience in utility infrastructure planning, cost allocation, and rate design.

Q11. NUMEROUS DOMINION WITNESSES STATE THAT JLARC HAS CONCLUDED THAT HIGH LOAD DATA CENTERS "ARE PAYING THEIR FAIR SHARE" CONSISTENT WITH THE CONCLUSION OF THE JLARC STUDY. DO YOU HAVE ANY COMMENTS ON THIS?

A11. Yes. It is important to put the conclusion found in the JLARC Study into proper context. On page 44 of the JLARC Study, JLARC states that: "Data centers are currently paying full cost of service." This conclusion is based on the cost recovery study performed by JLARC's energy consultant E3. The E3 study is included as an appendix to the JLARC Study. I have reviewed the E3 study and there are several observations that need to be made to put the JLARC conclusion into proper context.

First, the E3 study includes the following on the "Acknowledgements and Disclaimers" page:

> The authors would like to also thank the experts interviewed for this work, including representatives from load serving entities (Dominion Energy (Dominion), Northern Virginia Electric Cooperative (NOVEC), Mecklenburg Electric Cooperative (MEC)), and several data center companies (Amazon, Cloud HQ, Compass, Google, Meta, QTS, and Stack) for providing their perspectives and insights data center growth, operations, and cost of service studies.

Thus, it appears that E3 only interviewed representatives from load serving entities including Dominion and several large-use hyperscale data center customers to assist E3 in assessing cost of service studies. It is notable that E3 did not interview any cost-of-service experts on the Commission's Staff nor any ratepayer advocates. It is not surprising that limiting the interviews to the utilities and the High Load data center customers would lead to a conclusion that the data centers are paying their full cost of service.

Second, it appears that E3 limited its analysis to currently approved cost allocation methodologies for generation and transmission costs. There is no discussion in the E3 study of the actual cost allocation methodology used by Dominion to allocate generation plant – Average and Excess ("A&E") or the actual cost allocation methodology used by Dominion to allocate transmission plant – 12 Coincident Peak ("12-CP"). Nor is there any discussion of alternative cost allocation methodologies or any analyses of whether an alternative methodology may be a better fit on a going-forward basis given projected data center load growth and shifting load patterns.

Third, Dominion does not currently track and report on the costs to serve data center customers. Instead, data center customers are subsumed into Dominion's GS-3 and GS-4 rate classes. Thus, it is impossible to reach a definitive conclusion that High Load data center customers are "paying their full cost of service." Apparently, according to Dominion, this lack of transparency is one of the reasons that Dominion is proposing the new GS-5 rate class that will enable better tracking of the costs to serve High Load data center customers.[4]

[4] Baine Direct at 10.

Based on my review of the E3 study, the JLARC statement that "data centers are currently paying full cost of service"[5] means that, in JLARC's opinion, the GS-3 and GS-4 rate classes, inclusive of data center customers, are currently paying their full cost of service based on the *current* Commission approved cost allocation methodologies.

I do not disagree with that conclusion on where things stand today. But what is lacking is an evaluation of projected data center load growth and future load characteristics and whether the current class cost of service allocation methodologies for generation and transmission costs remain appropriate on a going forward basis. The JLARC Study does not address this broader question. I will discuss whether it may be appropriate to modify Dominion's current class cost of service methodologies later in my testimony. I believe that this is one of the threshold issues for the Commission to consider that makes this a case of first impression.

THIS IS A CASE OF FIRST IMPRESSION

Q12. WHAT FACTORS MAKE THIS A CASE OF FIRST IMPRESSION?

A12. There are numerous unique characteristics of serving High Load data center customers that revolve around the magnitude of their load usage and the speed at which this new type of customer is proliferating on the system. There are also several factors that make High Load data center customers unlike traditional large industrial customers. These include:

- Customer load size;
- Differing economic development impact of data centers versus large industrial customers on the load growth of other customer classes; and

[5] It also appears that E3 may have only considered whether data center customers' revenues are currently recovering their short term incremental, or marginal, costs and did not evaluate whether these data center customers are paying their "full cost of service" including the embedded costs of Dominion's existing generation and transmission system.

- Collective impact of data center load on peak demand and energy sales requirements.

The impact of High Load data center customers is already fundamentally changing the nature of both the Dominion system as well as the entire PJM RTO. The speed of the current and projected data center load growth is straining the ability of the grid to keep up with demand both in terms of generation and transmission requirements. This raises three fundamental questions.

1. Are High Load data center customers paying their fair share of costs under current cost allocation constructs and methodologies?
2. Are the current cost allocation methodologies still the most appropriate on a going forward basis?
3. Are existing non-data center customers adequately protected from the risks presented from the rapid and extensive infrastructure build out required to serve projected data center load growth?

To Dominion's credit, its proposal in this case addresses two of these questions. However, in my opinion, Dominion's proposal does not go far enough. The Commission's ultimate determination on the appropriate cost allocation methodologies, and the terms and conditions of service for High Load customers in the current case will set a precedent for future cases. Thus, this is a case of first impression that not only impacts future biennial reviews but also future RAC cases for the recovery of generation and transmission costs.

Q13. HOW DOES THE LOAD SIZE OF HIGH LOAD DATA CENTER CUSTOMERS DIFFER FROM TRADITIONAL INDUSTRIAL CUSTOMERS?

A13. When data centers first started initiating service in Dominion's service territory in the early 2010s, these customers did not look different from traditional high load factor industrial customers and Dominion assigned them to the GS-3 and GS-4 Rate Schedules as appropriate. In 2013, the average size of a data center customer was just 16 MW. This grew to an average size of 70 MW by 2024. However, Dominion witness Blackwell testifies that now the majority of requests are for 300 MW campuses. Further, Mr. Blackwell states that the Company has also received very large campus requests within the 2,400 to 7,000 MW range.[6]

Dominion does not have any traditional industrial customers that are anywhere near these load levels. Dominion's response to VCFUR Interrogatory No. 02-03, Attachment VCFUR Set 02-03 (LCY), indicates that the largest non-data center customer that Dominion plans to move to the new proposed GS-5 Rate Schedule has a contract demand of 178.572 MW. The other seven non-data center customers that Dominion proposes moving to Schedule GS-5 have contract demands of 100 MW or less. Further, Dominion's response to PEC Interrogatory No. 01-11 states that: "Over the past five years the Company has not received any load letters from non-data center customers for a load of 300 MW or more."[7]

Clearly, the new cohort of data center customers have loads that are not similar to traditional industrial customers and are several magnitudes greater in terms of size. Further, it is unclear whether the average size of data centers has plateaued or will continue to grow even bigger in the future.

[6] Blackwell Direct at 5.
[7] Selected responses to interrogatories referenced herein are included in Attachment GLA-2.

Q14. WHAT ARE THE DIFFERENCES IN THE ECONOMIC DEVELOPMENT IMPACTS OF LARGE DATA CENTER CUSTOMERS COMPARED TO TRADITIONAL INDUSTRIAL CUSTOMERS?

A14. I do not believe you can evaluate the economic development benefits of data centers in the same manner as traditional industrial customers and I have not attempted to do so. What is relevant for the current case is whether large investments in new data centers along with their large electric loads also create additional electric load growth among the other customer classes. According to the JLARC Study, after construction, a typical 250,000-square-foot data center may employ approximately 50 full-time workers. As a comparison, the Newport News Shipyard, with a similar load as a data center, currently employs about 25,000 full-time workers. In addition, there are a number of local firms that are suppliers to the Newport News Shipyard that also employ thousands of workers. All of these workers live and work in Newport News and the surrounding area supporting local grocery stores, restaurants, and big box retailers like Walmart and Costco. Thus, a new traditional industrial customer will not just cause an increase in electric load to serve the customer but also will lead to increases in residential, small commercial, and large commercial electric loads. If that were the case for new data center customers, then we would expect to see that reflected in Dominion's load forecast.

Q15. DOES THE LOAD FORECAST USED IN DOMINION'S 2024 IRP REFLECT LOAD GROWTH FOR THE NON-DATA CENTER CUSTOMERS AS A RESULT OF DATA CENTER LOAD GROWTH?

A15. No, it does not. Dominion's supplemental 2024 IRP filing removed the data center load from Dominion's load forecast. The tables from the supplemental filing reproduced below show the impact of removing projected data center load on Dominion's energy demand and coincident peak demand forecasts.

SCC Directed 2024 IRP Supplement Figure 2.1.1: Comparison of Energy Forecast – DOM LSE

	Energy (GWh)	
	2024 IRP	No Data Center Growth
2024	98,296	98,296
2025	99,307	97,761
2026	104,713	97,898
2027	107,693	98,127
2028	111,596	98,803
2029	115,058	98,955
2030	118,979	99,424
2031	122,949	100,011
2032	128,182	101,115
2033	132,684	101,515
2034	138,317	102,423
2035	144,476	103,484
2036	151,526	105,070
2037	158,049	105,844
2038	165,427	107,016
2039	172,999	108,329

SCC Directed 2024 IRP Supplement Figure 2.1.2: Comparison of Coincident Peak Demand Forecast

	CP (MW)	
	2024 IRP	No Data Center Growth
2024	17,353	17,353
2025	17,497	17,309
2026	18,147	17,300
2027	18,465	17,280
2028	18,870	17,290
2029	19,318	17,326
2030	19,787	17,376
2031	20,280	17,453
2032	20,875	17,548
2033	21,504	17,660
2034	22,245	17,818
2035	23,074	18,016
2036	23,985	18,269
2037	24,849	18,402
2038	25,708	18,480
2039	26,623	18,608

Removing projected data center load from the energy and coincident peak load forecasts reveals that the energy required to serve Dominion's other customers has a low annual rate of growth and actually decreases for the first three years through 2027 before returning to a relatively flat growth rate. The coincident peak demand forecast for Dominion's other customers similarly displays a negative annual growth for the first five years through 2029 and is basically unchanged in 2030 compared to 2024.

This projected negative growth and overall decrease in near term energy sales and coincident peak demand for the non-data center customers occurs at the same time that Dominion's projected data center load is increasing at a rapid rate. Thus, Dominion's data center load forecast is decoupled from the load growth for the other rate classes. In contrast, if a large traditional industrial customer were to build a new large manufacturing plant in Dominion's service territory, we would expect to see load growth occurring across the board in all rate classes in the vicinity of the plant.

Q16. WHY IS THIS SIGNIFICANT?

A16. Dominion's projected data center load growth will fundamentally shift the relationships and dynamics between and among the rate classes unlike what we have experienced before. For example, a supplemental transmission project that is required to serve a new data center customer is most likely solely needed to serve the data center customer. There are no associated increases in localized residential or commercial load as a result of the new data center. That is not the case for a transmission project required to serve a traditional industrial customer that employs hundreds of employees and requires numerous local suppliers. In that case, we would expect to see increases in localized demand across other rate classes served by the transmission project.

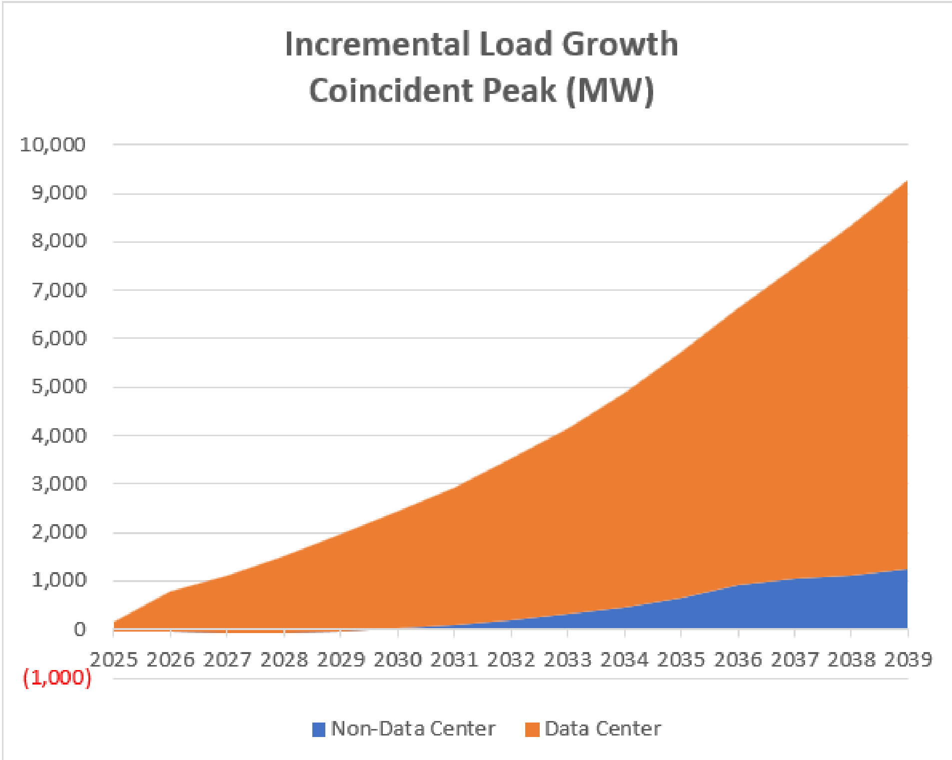
Q17. ARE THERE OTHER CHANGES IN THE DYNAMICS OF SERVING THE DIFFERENT RATE CLASSES CREATED BY NEW DATA CENTER LOAD?

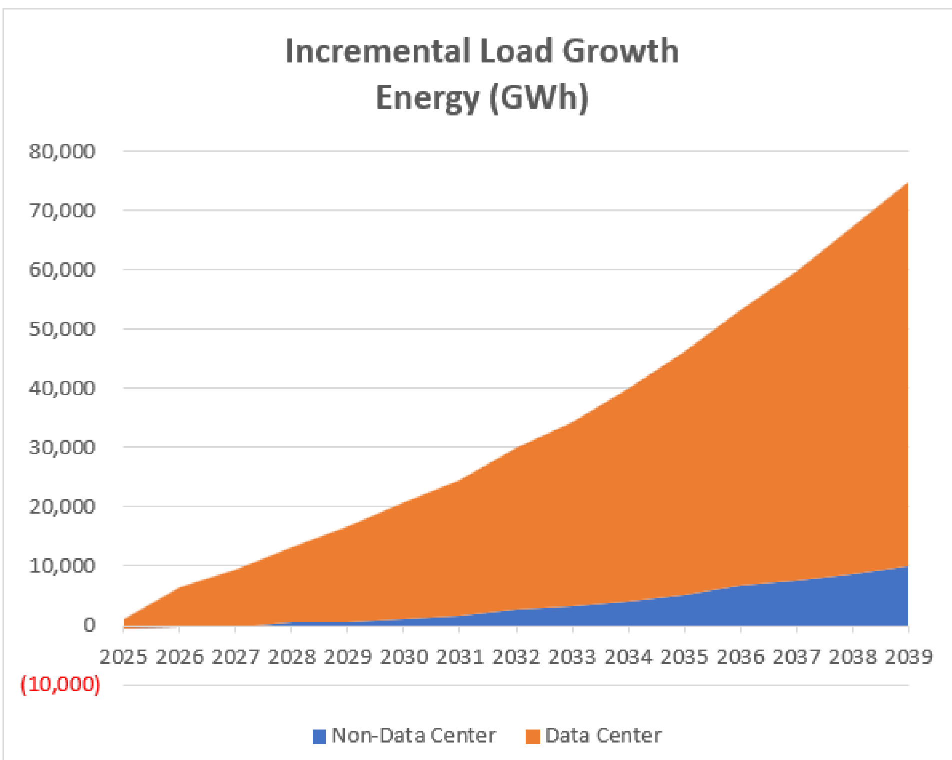
A17. Yes. The build plans presented in Dominion's 2024 IRP are designed to procure the required capacity to serve Dominion's coincident peak demand requirements, including the reserve margin, set by PJM and also to be able to meet Dominion's projected energy sales requirements.

Typically, higher capacity requirements to meet the projected coincident peak demand are viewed as being driven by low load factor customer classes.[8] For example, the summer air conditioning load of residential customers is much higher than their average load and is generally viewed as the main cost causer of the summer coincident peak demand spike.

Based on Dominion's load forecasts contained in its 2024 IRP and supplemental 2024 IRP filing, however, that no longer appears to be the case. The graphs below show projected incremental coincident peak demand and projected energy sales broken down between data center load and non-data center load over and above the 2024 levels based on the data provided in Dominion's supplemental 2024 IRP filing.

[8] The load factor is the ratio of average hourly load for the year to the peak hour load for the year. A low load factor means that the average hourly load is much lower than the peak hour of load. A high load factor means that the customer class's average hourly load is nearly the same as its peak hour load.


Incremental Load Growth
Coincident Peak (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
(1,000)
2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039
Non-Data Center
Data Center


Incremental Load Growth
Energy (GWh)
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
(10,000)
2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039
Non-Data Center
Data Center

The increased capacity requirements to serve peak loads through 2030 are almost entirely a result of the vast amounts of baseload energy required to serve data centers and not due to any increases in peak demands attributed to the summer cooling and winter heating needs of the non-data center low load factor customer classes. After 2030, baseload energy required to serve data centers remains the predominate cost causer for new generation resources to provide additional peaking capacity. In other words, the system coincident peaks are not growing because residential heating and cooling demands have grown "peakier" but rather because of the increase in baseload energy demands to serve data centers pushing the peaks up from the bottom. Thus, utilizing a peaking cost allocator to allocate the costs of generation resources may no longer be the best fit for Dominion's changing customer base and usage patterns among rate classes.

The charts above used data from Dominion's supplemental 2024 IRP filing based on an incremental data center load increase of 8 GW by 2039. However, on Dominion's recent Fourth Quarter earnings call, the Company told shareholders that it has 40 GW of data center capacity in various stages of contracting as of December 2024. The impact of a quintupling of data center peak load would show an even more dramatic impact from data center load growth.

Q18. DOES THE PROJECTED DATA CENTER LOAD GROWTH ALSO HAVE IMPLICATIONS FOR THE TYPE OF NEW GENERATION RESOURCES ADDED TO THE FLEET INCLUDED IN THE IRP?

A18. Yes. The projected high load factor data center load will change the overall Dominion LSE load factor over time. The table below shows the projected system load factors for

Dominion's system without data center load growth, for data center customers only, and the system inclusive of data center load.[9]

Year	DOM LSE W/O Data Center Load Factor	DOM LSE Data Center Only Load Factor	DOM LSE System Load Factor
2024	56%	93%	63%
2025	56%	93%	63%
2026	56%	92%	64%
2027	56%	93%	64%
2028	56%	92%	65%
2029	56%	93%	66%
2030	56%	93%	66%
2031	56%	93%	67%
2032	57%	93%	68%
2033	57%	93%	68%
2034	57%	93%	69%
2035	57%	93%	69%
2036	57%	93%	70%
2037	57%	93%	71%
2038	58%	92%	71%
2039	58%	92%	72%

The system load factor absent projected data center load is expected to remain fairly stable at 56-58%. The load factor for the data center load is also stable at 92-93%. However, the projected increase in data center load will cause the Dominion system load factor to steadily increase over time from 63% in 2024 to 72% by 2039. This is consistent with and reflective of the fact that the system coincident peak demand is growing from the bottom (baseload) up rather than being caused by new peaking demand from low load factor rate classes. A higher system load factor suggests that more baseload generation resources will be required as opposed to more peaking units. Further, a quintupling of incremental data center load growth as suggested in Dominion's recent Fourth Quarter earnings call would have an even more dramatic impact leading to an even higher system load factor.

[9] Based on data provided in Dominion's response to PEC Interrogatory No. 01-16.

Q19. DOES THE PROJECTED DATA CENTER LOAD GROWTH PRESENT COST AND RISK IMPLICATIONS FOR DOMINION'S NON-DATA CENTER CUSTOMERS?

A19. Yes. Dominion's supplemental 2024 IRP filing presents the results of the Commission directed model runs that removed data center load growth. Although a scenario with no additional data center load growth is unrealistic for planning the future, these model runs provide useful information about what the future looks like both with and without the projected data center load growth.

The following table from Dominion's supplemental 2024 IRP filing reproduced below shows the increase in the net present value ("NPV") cost and the incremental portfolio of generation and storage resources required to serve the projected data center load.

SCC Directed 2024 IRP Supplement Figure 3.1: Sensitivity Modeling Results

	2024 IRP		No Data Center Load Growth		Updated Capacity Pricing			
Portfolio	REC RPS Only with EPA	VCEA with EPA	REC RPS Only with EPA	VCEA with EPA	REC RPS Only with EPA	REC RPS Only with EPA	VCEA with EPA	VCEA with EPA
Data Center Growth	With	With	Without	Without	With	Without	With	Without
Net Present Value (NPV) Total ($B)	$100.2	$102.9	$77.2	$80.8	$100.3	$77.3	$103.3	$80.9
Solar (MW)	11,932	12,210	11,560	12,210	11,932	11,560	12,210	12,210
Wind (MW)	3,460	3,460	60	60	3,460	60	3,460	60
Storage (MW)	4,577	4,100	-	2,250	4,577	-	4,100	2,250
Nuclear (MW)	1,340	1,340	-	-	1,340	-	1,340	-
Natural Gas Fired (MW)	5,934	5,934	3,398	2,580	5,934	3,398	5,934	2,580
Retirements (MW)	-	-	-	-	-	-	-	-

The data presented in this table allows us to isolate the incremental increase in costs to serve the projected data center load. Further, it also allows us to identify the number and types of additional generation and storage resources that will be required to serve the projected data center load.

The NPV cost of the "VCEA with EPA" scenario inclusive of data center load with updated capacity pricing is $103.3 billion. Removing the projected data center load from this scenario yields an NPV cost of $80.9 billion. Thus, based on Dominion's modeling, the projected data center load growth imposes an incremental NPV cost of $22.4 billion. This modeling result may already be outdated. Dominion's recent Fourth Quarter earnings call suggested that the incremental data center load may be quintupled from the 8 MW that was modeled to 40 MW. If actually realized, this could potentially mean that the incremental NPV cost for data center load growth would similarly be quintupled to $112 billion.

The scenario with the projected data center load growth also requires a substantial increase in new generation and storage resources compared to the scenario without data center load growth. Absent data center load growth, the model results indicate that just an additional 2,580 MW of natural gas fired generation will be required over and above the renewable and storage resource requirements of the VCEA. However, to accommodate the large projected increase in data center load, in addition to these resources, an incremental increase of 3,400 MW of wind generation (or 3,460 MW total), 1,850 MW of energy storage (or 4,100 MW total), 1,340 MW of nuclear generation, and 3,354 MW of natural gas fired generation (or 5,934 MW total) is required.

Q20. DESCRIBE HOW THESE INCREMENTAL COSTS WILL TRANSLATE TO FUTURE RESIDENTIAL CUSTOMER BILLS AND THE RISKS TO RESIDENTIAL CUSTOMER BILLS IF THE DATA CENTER LOAD FORECAST DOES NOT MATERIALIZE.

A20. The load forecast, including the data center load forecast, drives the build plans identified by Dominion's modeling in the IRPs. The IRP build plans serve as the blueprint to support CPCN applications for new generation and transmission resources. If the data center load forecast does not materialize as projected, then there is a risk that Dominion will overbuild generation and transmission infrastructure and the non-data center customers will be left "holding the bag" to pay for the overbuild.

In the 2024 IRP, Dominion provides a typical bill analysis for the residential, commercial, and industrial customer classifications over the planning period. This bill analysis is provided under two different methodologies. The Commission directed methodology uses the class cost allocation factors based on the most recent year of actual data. Dominion's alternative methodology calculates bill impacts using projected class cost allocation factors that reflect the impact of the rapid data center load on the allocation factors. Thus, Dominion's methodology essentially shows what a typical residential monthly bill will be if the data center load comes in exactly as predicted. On the other hand, the Commission directed methodology shows what a typical residential monthly bill would be if none of the projected data center load shows up. A comparison of the projected typical residential monthly bill impacts under these two methodologies provides a fairly accurate depiction of the risks and potential rewards of data center load growth.

In the 2024 IRP Case that is currently pending before the Commission, Staff witness Welsh calculated the projected typical residential customer monthly bill based on the NPV cost of the build plan from Dominion's supplemental 2024 IRP filing for the scenario that removes data center load growth as directed by the Commission. The table below is reproduced from Staff witness Welsh's pre-filed testimony.[10] I have highlighted a few pertinent numbers in the table.

Residential Bill Impact Projection With and Without Data Center Load Growth

VCEA With EPA Portfolio

	Directed Methodology			Company Methodology		
	With Data Center Growth	No Data Center Growth	Difference	With Data Center Growth	No Data Center Growth	Difference
Dec. 2019	$122.66	$122.66	-	$122.66	$122.66	-
Dec. 2024	$140.18	$140.18	-	$140.18	$140.18	-
Dec. 2029	$193.07	$187.80	$5.27	$176.94	$183.30	-$6.36
Dec. 2034	$267.15	$221.15	$46.00	$213.67	$207.80	$5.87
Dec. 2039	$315.36	$242.16	$73.20	$214.24	$217.81	-$3.57
Total Bill Increase (2019-2039)	**$192.70**	**$119.50**	**$73.20**	**$91.58**	**$95.15**	**$(3.57)**

The bill analyses under these scenarios assume no change in current class cost allocation methodologies (for example, A&E method is used for generation plant, and 12-CP is used for transmission plant). Further, it also assumes that none of the incremental

[10] Case No. PUR-2024-00184, Welsh testimony at 7.

generation and transmission costs will be directly assigned to data center customers. Further, the bill analyses do not reflect the impact of Dominion's proposed new GS-5 rate class nor the proposed terms and conditions for High Load customers.

Under the scenario with no data center load growth, the Commission directed methodology that uses the most recent actual allocation factors would be accurate. The typical residential customer's monthly bill using 1,000 kWh under that scenario would be $242.16 in 2039.[11] In other words, if Dominion only constructed the build plan from the model runs in the supplemental 2024 IRP filing necessary to serve its customers with no additional data center load growth, then this is the projected monthly bill impact for a typical residential customer in 2039.

However, if we assume that Dominion's data center load forecast is 100% accurate, then the Company methodology would be more appropriate as the vast data center load growth would shift the calculation of the class allocation factors over the period. Under this scenario, Dominion incurs a greater cost to construct the necessary build plan to accommodate the projected data center load, but the overall system cost is spread out over significantly more billing determinants. Under this scenario, the typical residential customer monthly bill would be $214.24 in 2039. Thus, there is a potential benefit for all customers if Dominion successfully matches its build plan exactly with the future load demands of the data center customers.

However, there is also a very real possibility that Dominion will build the infrastructure to serve the projected data center load and the full amount of this load will

[11] It is not clear if this bill amount reflects the removal of approximately $2.4 billion of transmission projects identified in Dominion's supplemental 2024 IRP filing that are only needed to serve data centers. If these costs were not removed, but the billing determinants for projected data center growth were removed, then this bill impact is overstated.

not come. In this scenario, Dominion will have incurred the costs to serve the projected data center load, but the load does not show up. In that case, the Commission directed methodology that uses the most recent actual class allocation factors would be more accurate. If Dominion incurs an incremental NPV cost increase of $22.4 billion to serve a phantom data center load that does not materialize, then the non-data center customers will be left to foot the bill and the typical monthly residential customer bill would be $315.36 in 2039. Thus, the data center load forecast imposes a very real risk to non-data center customers.

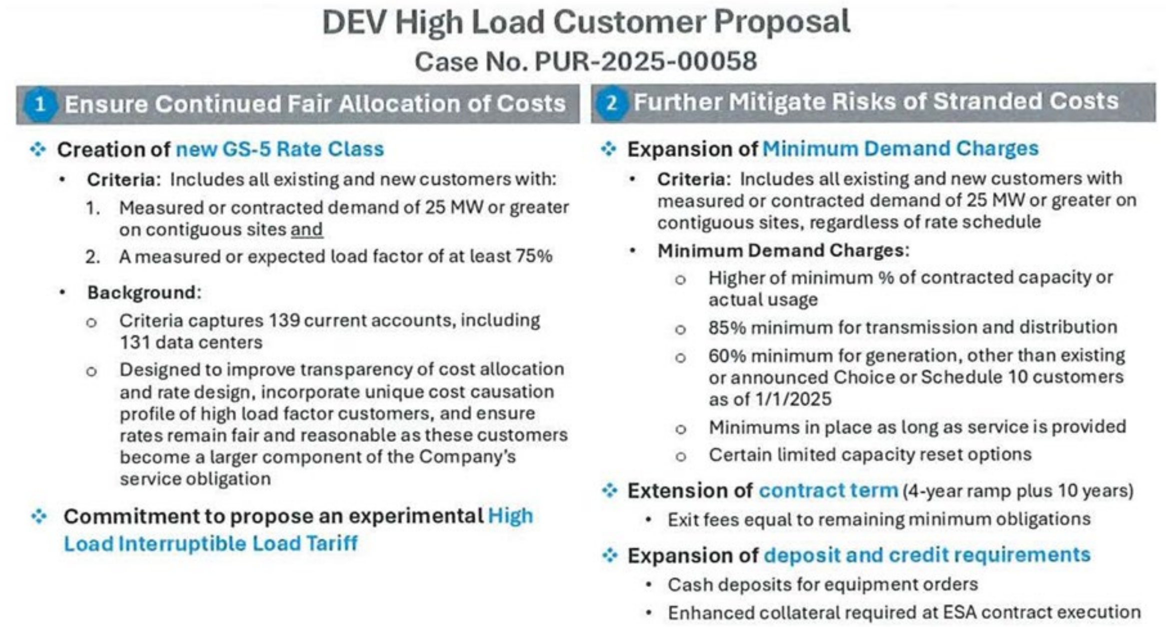
In summary, data center load growth could potentially benefit existing customers to the extent that system costs are spread across more and larger energy users. If Dominion's build plan for generation and transmission plant matches actual future data center load growth exactly, then residential customers could potentially realize a benefit of a lowering of the typical monthly bill from $242.16 to $214.24 in 2039. On the other hand, the magnitude and uncertainty of the data center load growth puts the residential customers at risk to pay much higher bills with a typical monthly bill potentially hitting $315.36 in 2039. It is unlikely that no new data center load will materialize in the future, but it is also unlikely that Dominion's data center load forecast is 100% accurate.

I commend the wisdom of the Commission in directing Dominion to perform additional model runs that removed the projected data center load. These model runs allow us to identify the NPV cost impacts, the incremental generation and storage resources required, and the bill impacts with and without the projected data center load. This information is invaluable in framing the extent of the costs and risks attendant to the rapid and uncertain data center load forecast. In a future without new data center load, a typical residential customer bill would be $242.16 in 2039. However, in a future with data center load growth, a typical residential customer bill in 2039 could range anywhere from a low of $214.24 (if Dominion's load forecast is 100% accurate) to a high of $315.36 (if none of Dominion's load forecast occurs). This wide range is a testament to the large magnitude and uncertainty of the projected data center load forecast and the risks borne by existing customers under existing cost allocation methodologies and rate designs.

DOMINION'S PROPOSED SOLUTION

Q21. PLEASE PROVIDE AN OVERVIEW OF DOMINION'S PROPOSAL TO ADDRESS THE COSTS AND RISKS ASSOCIATED WITH THE DATA CENTER LOAD FORECAST TO DOMINION'S NON-DATA CENTER CUSTOMERS.

A21. Dominion's proposed new GS-5 rate class and proposed new terms and conditions for High Load customers addresses many of the topics and issues delineated in the Commission's Scheduling Order in Case No. PUR-2024-00144 and the subsequent live discussion by panelists at the December 16, 2024 Technical Review Conference held before the Commission. Dominion witness Baine provides an infographic on page 10 of his direct testimony that provides a summary of Dominion's proposal. This infographic is reproduced below.



Item 1 on the left side of the infographic is proposed to address the question of whether data center customers are paying their fair share of system costs. The new GS-5 rate class will allow for more transparency and better tracking of the costs incurred to serve data centers and, presumably, this could potentially lead to future changes in cost allocation and/or rate design if it is revealed that data centers are not paying their fair share of costs in the future.

Item 2 on the right side of the infographic addresses the question of whether existing non-data center customers are adequately protected from the risks presented from the rapid and extensive infrastructure build out required to serve projected data center load growth. Item 2 provides a summary of the proposed terms and conditions designed to address the risk associated with Dominion's load forecast. If the data center load forecast proves to be overstated, leading to Dominion potentially overbuilding distribution, transmission, and generation infrastructure, then the proposed terms and conditions are designed to partially shift some of this risk and cost responsibility back onto the High Load data center customers.

Although both of these questions are important, the risk associated with overbuilding distribution, transmission, and generation infrastructure due to an inaccurate data center load forecast is vitally important for the Commission to address in the current case.

Q22. PLEASE PROVIDE AN OVERVIEW OF THE RISK INHERENT IN DOMINION'S LOAD FORECAST AND WHY ADDITIONAL RATEPAYER PROTECTIONS ARE NEEDED.

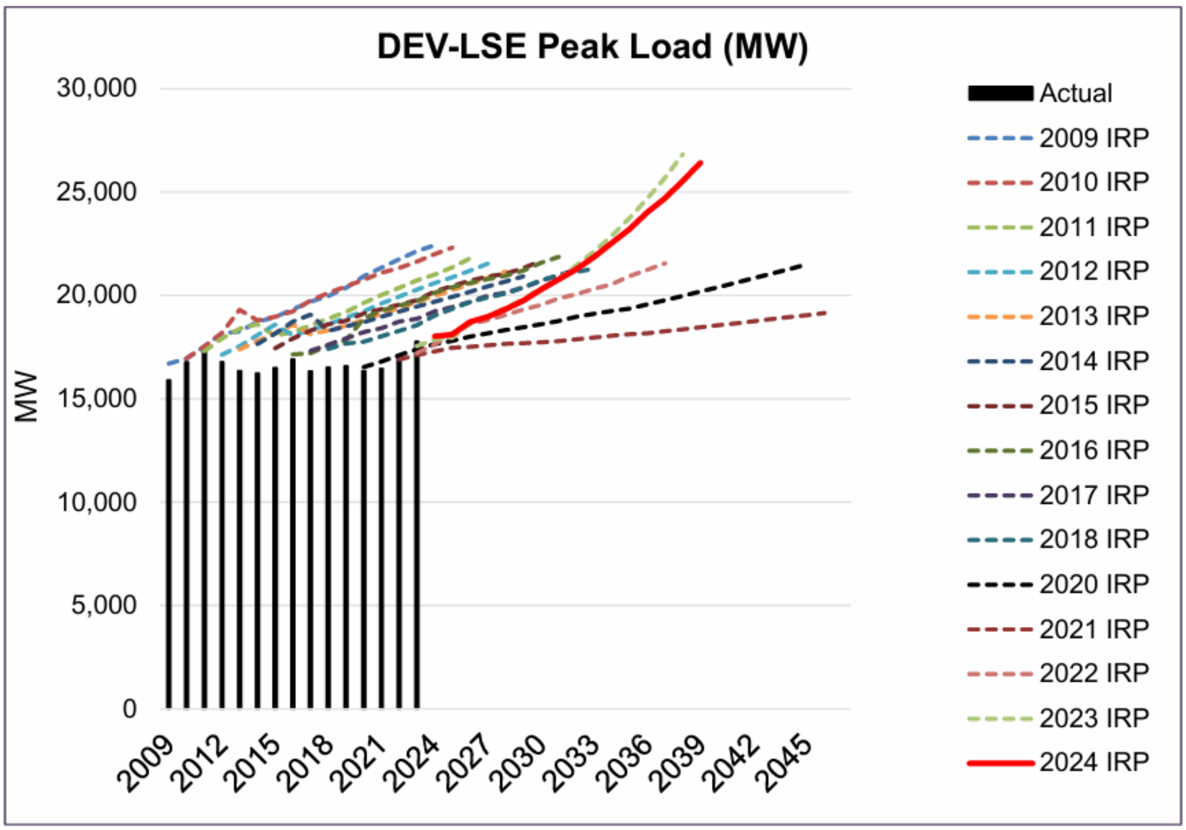
A22. Dominion's load forecasts are not usually a topic of consideration in biennial rate reviews. Instead, Dominion's load forecast is litigated as part of Dominion's IRP cases. The 2024 IRP Case is currently pending before the Commission. In that case, numerous parties, including Staff, questioned the load forecast and raised issues with the data center load forecast in particular. Whether Dominion's load forecast is appropriate for use for the 2024 IRP will be addressed by the Commission in that case. What is relevant for the issues in the current case, however, is the uncertainty of the data center load forecast.

Regulated vertically integrated utilities like Dominion have strong incentives to overbuild infrastructure. Dominion has a financial incentive to overbuild because it is allowed to earn a rate of return, recovered through customer rates, based on its total rate base (the total value of its infrastructure). Thus, the higher the value of the infrastructure, the more profit Dominion realizes.[12] Dominion also has a social incentive to err on the side of building too much infrastructure to provide greater system reliability rather than too

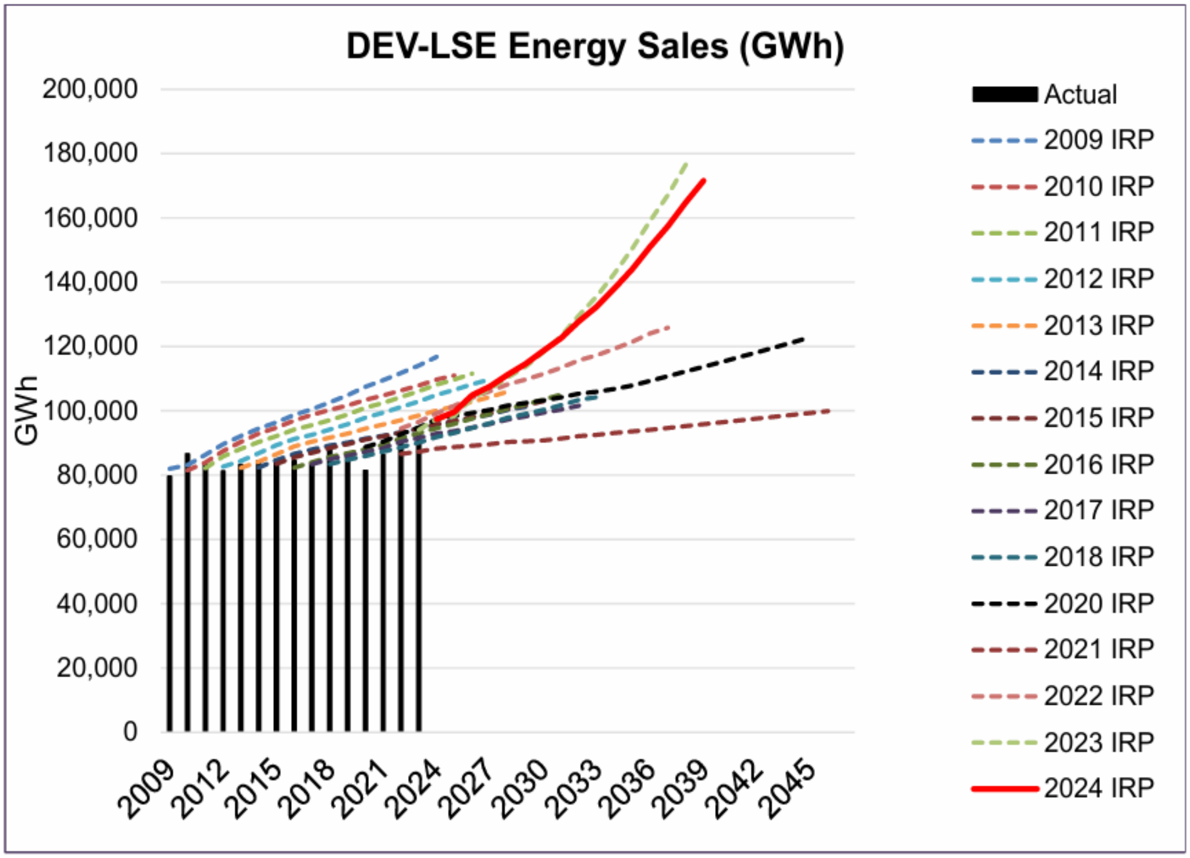
[12] Dominion earns a relatively higher ROE on transmission plant due to various FERC approved adders to base ROE.

little that could lead to service disruptions. Thus, Dominion has a double incentive to rely on overly optimistic load forecasts.

This is corroborated by a comparison of Dominion's historic load forecasts with subsequent actual load data. In the 2024 IRP Case, Staff witness Curtis's testimony includes the Enverus Report.[13] The figures below are reproduced from the Enverus report[14] showing Dominion's peak load and energy sales forecasts from prior IRPs compared to actual data.



[13] See Hearing Exhibit 49 in Case No. PUR-2024-00184.
[14] Enverus Report at 16 and 18.



Two observations are clear from visually examining these charts. First, the overall bias to the upside of Dominion's load forecasts relative to subsequent actual data is apparent for all of the IRPs. Secondly, the load forecasts for the 2023 and 2024 IRPs display a sharp shift in trajectory to even higher levels reflective of the new data center load forecast.

In recent years, Dominion was directed by the Commission to use the PJM load forecast for the DOM Zone stepped down to the Dominion LSE level. PJM relies on data center forecast data that they receive from Dominion and several electric cooperatives in Virginia. Dominion's data center load forecast is based on the contracts that Dominion has executed with various data center customers for future service. The Dominion data center load forecast along with the supporting contract capacity information on the executed contracts is provided to PJM. Thus, the accuracy of Dominion's data center load forecast and PJM's load forecast is dependent on the accuracy of the data center customers fully utilizing their contracted capacity.[15]

This raises the concern that if Dominion's current rate schedules and terms and conditions allow for an unfair socialization of costs to other ratepayers, then data center customers may have an incentive to overestimate their contract loads. Doing so, would preserve the optionality of future expansion at the data center campuses potentially at the expense of the other ratepayers. If this is occurring, then it will lead to overly optimistic load growth forecasts and an excessive buildout of infrastructure. Therefore, the proposed changes to the terms and conditions in this case not only can serve to protect ratepayers from unfairly subsidizing the costs to serve data centers, but also can lead to more accurate load forecasts in the first place and prevent the overbuilding of infrastructure.

Q23. DOES DOMINION ACKNOWLEDGE THAT ITS PROPOSED TERMS AND CONDITIONS CAN LEAD TO MORE ACCURATE LOAD FORECASTS?

A23. It appears that Dominion agrees with this. Dominion witness Wishart states on page 20 of his direct testimony the following: "Additionally, minimum bills help prevent speculative development by requiring data centers to commit to a baseline level of energy usage, discouraging them from overestimating their needs and blocking grid capacity that could be used by other customers. Minimum bill provisions also provide customers with an incentive to not overestimate their expected load when requesting service from the Company. Absent minimum bill requirements, new customers could request service based on the most optimistic forecast of future peak demand without consequence."

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[15] This problem becomes particularly acute given Dominion's statement in its fourth quarter earnings call that it now has 40 GW of data center capacity at various stages of contracting.

Q24. IS THERE ANY EVIDENCE THAT DATA CENTER CUSTOMERS HAVE OVERSTATED THEIR CONTRACT DEMANDS?

A24. Dominion's response to VCFUR Interrogatory No. 02-03, Attachment VCFUR Set 02-03 (LCY) and Attachment VCFUR Set 02-03 (KMS) provided the actual measured peak demand, the contract demand, and the contract effective date for all customers that Dominion proposes moving to the new GS-5 rate schedule. There are 131 data center customers and 8 non-data center customers that will be moved to the GS-5 rate schedule.

As a whole, this group of customers had a combined contract demand of 5,215.9 MW and a combined measured peak demand of 3,132.6 MW, or 60.06% of their contract demand. The 131 data center customers had a combined contract capacity (demand) of 4,664.9 MW and a combined measured peak demand of 2,782.2 MW, or 59.64% of their contract demand. Thus, the data center customers' actual peak demands are substantially lower than their contract demands. However, many of these data center customers have relatively recent contract effective dates and may still be ramping up to full contract demand levels.

I identified 16 data center customers with contract effective dates of 2020 or earlier that also began receiving service in 2020 or earlier. These customers should be fully ramped up. These 16 data center customers had a combined contract demand of 630.4 MW and a combined measured peak demand of 301.7 MW, or just 47.86% of contract demand.

Based on the limited actual data available for review, it appears that data center customers are contracting for more capacity than they currently need. This lends credence to Dominion witness Wishart's statement that: "Absent minimum bill requirements, new customers could request service based on the most optimistic forecast of future peak demand without consequence."

PROPOSED MINIMUM BILL PROVISIONS

Q25. WHAT ARE THE PROPOSED MINIMUM BILL PROVISIONS FOR HIGH LOAD CUSTOMERS?

A25. As of January 1, 2027, Dominion proposes that the Schedule GS-5 customers be billed on the greater of their actual measured demand or 85% of their contracted demand for distribution and transmission charges, and 60% of their stated contract demand for generation charges. This would apply to all distribution, transmission, and generation demand charges including base rates and all applicable RACs. Thus, a data center customer with a contract demand of 100 MW would pay minimum distribution and transmission charges based on 85 MW and minimum generation charges based on 60 MW of demand regardless of their actual demand. These minimums would be ratcheted up to a higher demand level if this customer's actual measured demand exceeded the 100 MW contract demand.[16]

These proposed minimum charges are also included in Dominion's exit fees should a data center customer decide to terminate service before the contract term is over. The exit fee would be equal to the minimum monthly charges calculated by multiplying the base rate and RAC demand charges times the appropriate minimum percentage of contract demand (85% for distribution and transmission, 60% for generation) over the remaining term of the contract.[17]

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[16] See Blackwell Direct at 19.
[17] See Blackwell Direct at 11, 22.

Thus, Dominion's proposed minimum charges would provide some level of protection for non-data center customers. They would also provide some financial incentive to prospective data center customers to provide a more accurate estimate of their actual load requirements. However, the advertised minimums are not an accurate depiction of the risk left to the other ratepayers.

Q26. WHY DO YOU SAY THAT?

A26. On page 20 of Dominion witness Blackwell's testimony, he states the following: "Under the Company's proposal, once a customer signs an ESA and a meter is set, the proposed rate schedule changes will allow the customer to make a one-time election, with 36 months' notice, to reduce its contracted capacity by up to 20%, without penalty."

The contract capacities in the executed contracts for data centers are a foundational element of Dominion's and PJM's load forecasts. Dominion uses these load forecasts to plan for (IRPs), apply for (CPCNs), and construct transmission and generation plant. Some of these projects could be approved by the Commission and in service within this 36-month grace period. It is problematic if the data center customer has the sole discretion and ability to reduce its contracted demand by 20% without penalty after the meter is set. For example, if a supplemental transmission project was required to serve a data center campus and the costs were determined through a PJM "do no harm" analysis, then that analysis would likely have yielded a different solution and a lower cost for a data center contract demand that is 20% lower because the data center customer exercised this optionality after the fact. Unless there is excess generation and transmission capacity available, any reduction in these contracted loads means someone else is required to pay for the lost revenues no longer collected from the data center customer due to the 20% reduction in the data center customer's contracted capacity.

Under Dominion's proposal, a data center customer with an initial contract demand of 100 MW that executes this 20% reduction option will now have its minimum charges based on 80 MW instead of the original 100 MW. This customer would pay minimum distribution and transmission charges based on 68 MW (85% of 80 MW) and minimum generation charges based on 51 MW (85% of 60 MW) of demand regardless of their actual demand. The table below summarizes the risk reduction offered by Dominion's proposed minimum charges and the impact of this optionality to reduce contract minimums.

	Advertised Minimum Percentage	Effective Minimum Percentage
Distribution	85.00%	68.00%
Transmission	85.00%	68.00%
Generation	60.00%	51.00%

Providing the data center customers with the sole discretion to reduce their contract capacity by 20% significantly reduces their risk, shifts the risk to other customers, and undermines the incentive to provide more accurate load requirements when negotiating contracts with Dominion. When entering into the initial contract, the data center customers only have to estimate their actual capacity needs within 68% for distribution and transmission and within 51% for generation before any financial penalty is realized. This hardly inspires confidence in the accuracy of the contract demands and by extension the data center load forecast.

In addition, giving the data center customers the sole discretion to reduce their contract capacity by 20% would also reduce the exit fee by 20%, further shifting stranded cost risks to be borne by non-data center customers.

Dominion witness Blackwell also states on page 20 of his direct testimony that: "In addition, the customer may reduce its contracted capacity by up to an additional 30%, up to a total of 50% reduction from the original contracted capacity, with a new 36-month notice, at the utility's discretion, if the Company can "re-market" that capacity to meet other customer and system needs."

Q27. IN YOUR OPINION, IS IT REASONABLE FOR DOMINION'S TERMS AND CONDITIONS TO ALLOW MULTIPLE CAPACITY REDUCTIONS OF THIS MAGNITUDE?

A27. Given the fact that Dominion's supplemental 2024 IRP filing identified an incremental NPV cost of $22.4 billion of infrastructure required to serve the projected data center load, it does not seem reasonable to allow the data center customers to have sole discretion to lower their contract demands by 20%. Previously, such requests were at the discretion of Dominion alone. Secondly, given the size of these new data centers, it may no longer be reasonable to allow Dominion the discretion to lower a data center customer's contract capacity without some level of oversight by the Commission or its Staff. For example, Mr. Blackwell states that Dominion has received very large data center campus requests up to 7,000 MW. If a customer of this size were to exercise its sole discretion, as proposed by Dominion, to lower its contract demand by 20%, then this would be a reduction of 1,400 MW, or the equivalent of a Greensville power station. Allowing a further reduction of 30% at Dominion's discretion would be an additional 2,100 MW for a total of 3,500 MW reduction.

Q28. WHAT DO YOU PROPOSE FOR MINIMUM CHARGES?

A28. I think it is important to consider Dominion's dominant position in the data center market and the importance of the precedent that will be set by the Commission in this case for other jurisdictions. What happens in Virginia in this case will likely set the standard for other jurisdictions to follow. Dominion's proposal has been partially informed by a review of similar proposals of peer utilities in other jurisdictions. However, when it comes to serving data center load, Dominion has no peers. Dominion witness Blackwell states that the Northern Virginia data center market is greater than the next five largest U.S. markets combined and that 70% of the world's internet traffic flows through Northern Virginia.[18] Quite frankly, the stakes in Virginia for Dominion and its customers are much higher than those faced by other utilities in other states. As such, it is the position of PEC that the protections for non-data center customers should be more strenuous to reflect the greater risk that this large load growth presents to Virginia ratepayers.

I recommend that proposed Schedule GS-5 customers be billed on the greater of their actual measured demand or 90% of their contracted capacity for distribution, transmission, and generation charges. I further recommend that a GS-5 customer be allowed to make a one-time election, with 36 months' notice, to reduce its contracted capacity by up to 10%, without penalty. Thus, I recommend cutting the customer's discretion to reduce its contracted capacity in half from Dominion's proposed 20% down to 10%. My proposal to increase the minimum percentages to 90% of contracted capacity for distribution, transmission, and generation charges provides a higher level of protection for the non-data center customers while still leaving some flexibility for GS-5 customers to adjust their contracted capacity. The table below provides a comparison of Dominion's

[18] Blackwell Direct at 3.

proposal to PEC's proposal for minimum charges and the optionality to reduce contract minimums.

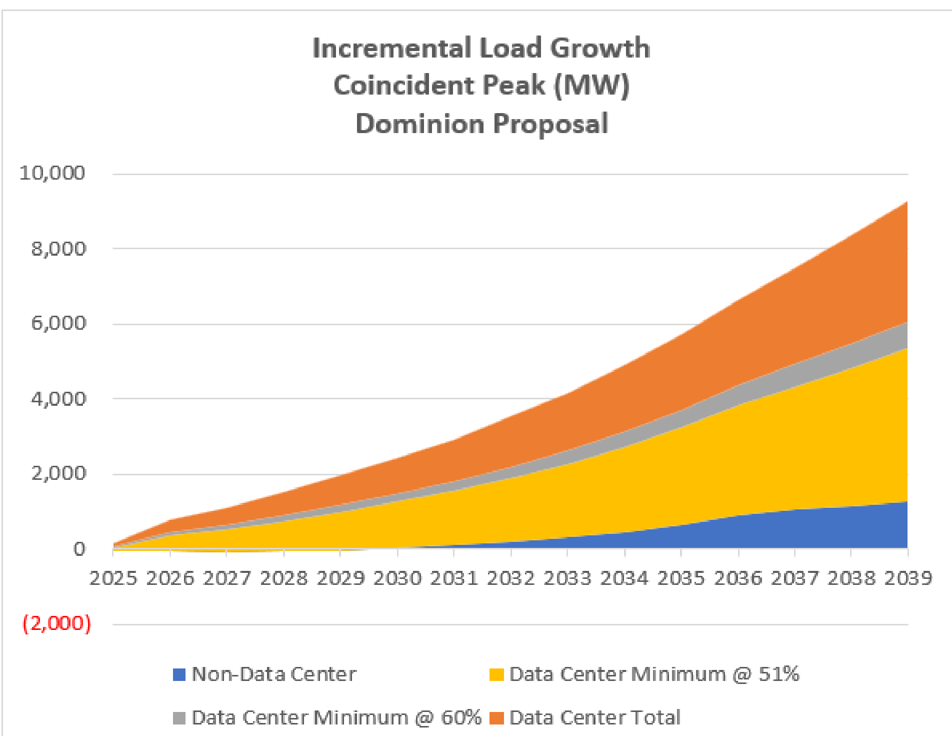
	Dominion Proposal		PEC Proposal	
	Top Line Minimum Percentage	Effective Minimum Percentage	Top Line Minimum Percentage	Effective Minimum Percentage
Distribution	85.00%	68.00%	90.00%	81.00%
Transmission	85.00%	68.00%	90.00%	81.00%
Generation	60.00%	51.00%	90.00%	81.00%

Under PEC's proposal, a GS-5 customer with a contract capacity of 100 MW would pay minimum demand charges based on 90 MW and if this customer exercised its discretion to reduce its contract capacity by 10%, or 10 MW, then this customer would pay minimum demand charges on 81 MW (90% of 90 MW). This proposal also will provide a greater incentive to data center customers to provide accurate load estimates to be included in contract capacity and will discourage the inclusion of speculative load.

At a minimum, I recommend that the Commission require Dominion to report on any reductions in contract capacity requirements for these customers made under the data center customers' discretion (assuming this is approved by the Commission) and at Dominion's discretion. This information could be valuable to the Commission. For example, if Dominion files for approval of a CPCN for a new gas-fired generation unit and, after filing the application, a large data center customer notifies Dominion that it is reducing its contract capacity by 20%, then this could mean that the new gas-fired plant is no longer needed. Requiring Dominion to timely report on these reductions to data center contract capacity will provide more transparency to Staff in evaluating future Dominion proposals.

Q29. DO YOU HAVE ANY COMMENTS ON DOMINION'S PROPOSED MINIMUM FOR GENERATION DEMAND CHARGES TO BE BASED ON JUST 60 PERCENT OF CONTRACT DEMAND?

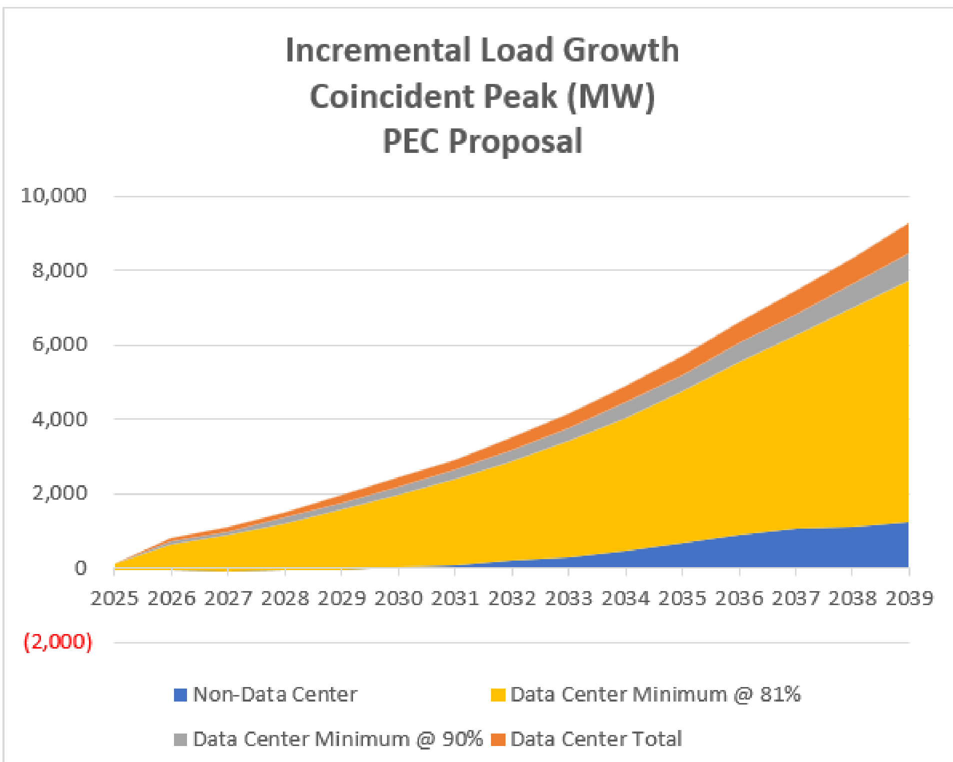
A29. Yes. I don't see any reason for Dominion to propose a much lower minimum percentage for generation (60%) compared to distribution and transmission (85%). Dominion's supplemental 2024 IRP filing identified significant additional generation and storage resources that will be required to serve the incremental data center load growth. The additional nuclear, offshore wind, gas-fired, and storage resources are high-cost resources and Dominion's own analysis indicates that large quantities of all of these resources will be required at an incremental NPV cost of $22.4 billion. If the data center load does not materialize as predicted, these costs will be recovered through the rates paid by the non-data center customers. The potential risk of cost shifting these generation costs to other customers under Dominion's proposal is depicted in the chart below.



Dominion's 2024 IRP identified a build plan for additional resources to serve the entire area under this curve. The area shaded in blue is the projected increase in coincident peak demand over and above the 2024 level for Dominion's non-data center customers. The remaining area including the area shaded in orange is the projected increase in coincident peak demand of Dominion's data center customers. The orange shaded area is the amount of data center demand that is not covered by the proposed 60% minimum for data center demand charges. The top line 60% minimum includes both the grey and gold shaded areas. However, Dominion proposes that data center customers be allowed the discretion for a one-time reduction in contract capacity of 20%. Thus, the actual area fully covered by Dominion's effective minimum of 51% is the area shaded in gold. Dominion is planning to build generation and storage resources to serve all of the shaded areas. However, Dominion's proposal puts the other ratepayers at risk to pay for the generation and storage resources necessary to serve the orange and grey shaded areas in the chart in the event that the data center load forecast is overstated.

Staff performed a typical residential bill analysis in the 2024 IRP Case that showed a range of potential monthly bills in 2039 from a high of $315.36 to a low of $214.24. In the chart above, if Dominion builds the resources to serve the entire projected load including the orange shaded area and the actual data center load actually meets this forecast exactly, then this would be consistent with the typical residential monthly bill in 2039 being at the low end of the range, or $214.24. On the other hand, if Dominion builds resources to serve the entire curve but none of the projected data center load occurs shown as the blue shaded area on the chart, then this would be consistent with the typical residential monthly bill in 2039 being at the high end of the range, or $315.36. Dominion's proposal would guarantee, through its proposed minimum demand charges, that this high end of typical bills would be reduced to the level consistent with the gold shaded area in the chart. Thus, the low end of typical residential bills remains unchanged but the high end is reduced by Dominion's proposal. Hence, the risk of cost shifting to other ratepayers is reduced.

I prepared a similar chart for PEC's proposal for a 90% generation minimum for data center demand charges. The chart below shows that PEC's proposal shrinks the orange and grey shaded areas and further reduces the risk of cost shifting to other customers of the generation costs to serve data center customer load that fails to materialize as projected.



<u>**PROPOSED EXTENSION OF CONTRACT TERM**</u>

Q30. PLEASE PROVIDE AN OVERVIEW OF DOMINION'S PROPOSED CONTRACT TERM FOR HIGH LOAD CUSTOMERS.

A30. Dominion proposes establishing a fixed contract term for new customer accounts requesting capacity of 25 MW or greater on a single or contiguous properties. The term as proposed is a total of 14 years, inclusive of a 4-year ramp period to achieve total capacity (4-year ramp + 10 years). In terms of ramp schedule, customers will have the choice of a 4-year ramp at an incremental rate of 20% per year or 100% of requested capacity at initial energization.[19]

The proposed 14-year term is used to calculate the exit fee for any High Load customer that ceases operation or otherwise defaults on its contract. The exit fee will collect the remainder of the minimum charges over the remaining term of the contract. This is another measure proposed by Dominion to lower the risk to its other customers. The revenues collected through the exit fee will reduce the amount of costs that are shifted to other customers in the event of a default on the contract. Thus, a longer contract term will assign more risk to the High Load customer and less risk to other customers. Conversely, a shorter contract term will assign less risk to the High Load customer and more risk to other customers.

Q31. DO YOU HAVE ANY COMMENTS ON DOMINION'S PROPOSED 14-YEAR CONTRACT TERM?

A31. Yes. I appreciate Dominion making a proposal aimed at reducing the risk and the potential shifting of costs to other customers. Respectfully, however, I do not believe it goes far enough. Given the Company's data center load growth forecast and the incremental NPV cost (price tag) of $22.4 billion that Dominion's supplemental 2024 IRP filing identified

[19] Blackwell Direct at 21.

to serve the projected data center load growth, I believe a longer contract term and a faster ramp schedule is justified.

Q32. WHAT IS YOUR RECOMMENDATION FOR THE CONTRACT TERM AND RAMP SCHEDULE?

A32. I recommend a total contract term of 20 years and an accelerated ramp schedule. I performed a simplified analysis to determine how much undepreciated plant would be remaining at the end of the Company's proposed 14-year term and PEC's proposed 20-year term. I assumed that the incremental plant would have a service life of 36 years and used a straight-line depreciation method with no salvage value.

Starting with a capex of $22.4 billion, after 14 years there would still be an undepreciated plant balance of $13.69 billion, or 61.1%. Even assuming, then, that the anticipated data center demand fully materialized and the High Load customers honored their contractual obligations, more than 61% of the incremental infrastructure costs would remain undepreciated and unrecovered at the end of Dominion's proposed 14-year contract term.

At the end of PEC's proposed 20-year term, there would still be an undepreciated plant balance of $9.96 billion. Thus, about 44% of the incremental infrastructure costs would remain undepreciated and unrecovered at the end of PEC's proposed 20-year contract term. Thus, PEC's proposal offers greater protection against potential cost shifting of costs to Dominion's other customers incurred due to the projected data center load growth proving to be inaccurate.

This is an overly simplified analysis that used the incremental NPV costs identified by Dominion. In reality a whole host of costs will occur at different times and the nominal cost will be much higher than $22.4 billion. Also, distribution, transmission and generation plant have differing service lives, depreciation rates and potential salvage value. Nevertheless, the undepreciated plant balance at the end of a 20-year term will be meaningfully lower than at the end of a 14-year term under any set of assumptions.

A 20-year contract term would also increase the exit fee in the event a High Load customer ceases operation before the end of the contract. This provides additional protection to mitigate the risks borne by other customers.

Q33. WHAT IS YOUR RECOMMENDATION FOR A FASTER RAMP RATE?

A33. The term proposed by PEC is a total of 20 years, inclusive of a 3-year ramp period to achieve total capacity (3-year ramp + 17 years).

The full costs to serve a High Load customer are incurred on the front end before the customer takes the first electrons. It is understandable that the High Load customer may not be ready to take the full contract capacity on day one and Dominion's ramp schedule allows the customer flexibility to grow into it over four years. Nevertheless, any revenues that are not able to be collected from the High Load customer in those early years are, by default, collected from Dominion's other customers. Somebody has to pay. The table below shows Dominion's proposed ramp schedule and the percentage of costs that are shifted to other ratepayers each year.

Dominion Proposal

Year	Load Ramp	Other Ratepayer Responsibility
1	20%	80%
2	40%	60%
3	60%	40%
4	80%	20%
5	100%	0%

Regardless of the ability of the High Load customer to take the full load on day one of service, the full revenue requirement must be collected each year. The amount not collected from the High Load customer is shifted to other ratepayers.[20] I propose that the ramp schedule be more front loaded and shortened by one year as shown in the table below.

PEC Proposal

Year	Load Ramp	Other Ratepayer Responsibility
1	40%	60%
2	60%	40%
3	80%	20%
4	100%	0%
5	100%	0%

PEC's proposed ramp schedule still allows some flexibility for the High Load customer to grow into its contract capacity but it offers greater protection against cost shifting to other ratepayers compared to Dominion's proposal.

Q34. PLEASE SUMMARIZE YOUR ASSESSMENT OF DOMINION'S PROPOSED TERMS AND CONDITIONS TO MITIGATE THE RISK OF STRANDED COSTS AND COST SHIFTING TO OTHER CUSTOMERS.

A34. Dominion's proposed minimum charges, exit fees, longer contract term and ramp schedule are all aimed at mitigating risk and limiting the potential of shifting costs to other customers. I welcome these proposals and believe Dominion made a good faith effort to address the topics and issues delineated in the Commission's Scheduling Order in Case No. PUR-2024-00144 and the subsequent live discussion by panelists at the December 16, 2024 Technical Review Conference held before the Commission. However, from PEC's

[20] The other ratepayer responsibility reflected in the table assumes that the High Load customer is able to meet or exceed the ramp target each year. If the customer does not, then the minimum demand charges will be assessed based on Dominion's proposed minimum percentages applied to each year's ramp target. In that event, the other ratepayer responsibility will be higher than what is shown in this table.

perspective, Dominion's proposed changes to its terms and conditions do not go far enough.

Although I request that the Commission adopt all of my recommendations, it is clear that the Commission has a number of different levers available to it that can mitigate against the risk of incurring stranded costs. Which levers are appropriate and in what amounts is solely a matter for the Commission's discretion. In addition to the proposed terms and conditions already discussed, there are also other avenues available to mitigate risk through the direct assignment of costs to High Load customers where appropriate and a reexamination of the appropriate class cost of service study methodology going forward.

DIRECT ASSIGNMENT OF COSTS

Q35. CAN THE INCREMENTAL COSTS IDENTIFIED IN DOMINION'S SUPPLEMENTAL 2024 IRP FILING BE DIRECTLY ASSIGNED TO DATA CENTER CUSTOMERS?

A35. Most of the plant that will be constructed to accommodate the projected data center load will also serve other customers. It may be an appealing idea to directly assign the full incremental NPV cost identified to serve this load to the data center customers, but in my opinion that would not be consistent with accepted cost allocation principles.

Generally speaking, costs should only be directly assigned when they are incurred to serve a single customer or group of customers. For example, Columbia Gas of Virginia ("Columbia") constructed a 13.5-mile, 24-inch diameter, high-pressure natural gas lateral to connect Dominion's Bear Garden combined cycle power plant to the interstate gas pipeline facilities of Transcontinental Gas Pipe Line Corporation. Dominion is the only customer on this lateral and the sole reason it was constructed was to serve the Bear Garden plant. Columbia directly assigned the costs of this lateral pipeline to Dominion instead of socializing these costs into the Mains cost account and allocating the costs to all customer classes.

Other examples of direct assignment include distribution-style poles that support streetlights and conductor spans to such poles and short tap lines from a main primary voltage line to supply a single primary voltage customer's premises. Another example of direct assignment would be merchant generation plants that interconnect onto the transmission grid in Virginia. Any required system upgrade costs are directly assigned to the merchant plant and collected as a contribution in aid of construction ("CIAC").

Q36. SHOULD ANY OF THE INCREMENTAL GENERATION COSTS TO SERVE THE PROJECTED DATA CENTER LOAD BE DIRECTLY ASSIGNED TO DATA CENTER CUSTOMERS?

A36. The Commission's Scheduling Order in Case No. PUR-2024-00144 raised the possibility of directly assigning generation costs. One of the topics flagged for discussion at the Technical Conference was "whether certain generation costs should be directly assigned to a new large-use customer class."

In my opinion, the generation units identified in Dominion's 2024 IRP and Supplemental 2024 IRP filing do not meet the criteria for direct assignment. Once these units are placed into service, the electricity produced will serve all of Dominion's customers as well as enabling more off-system sales into PJM and/or fewer energy purchases from PJM. To the extent that the Commission shares PEC's concern with the magnitude of the incremental generation costs identified as being driven by data center load growth, it would be better to address this fairness issue by reconsidering the class cost of service ("CCOS") methodology for generation resources in light of the projected data center load forecast.

Q37. SHOULD ANY OF THE INCREMENTAL TRANSMISSION COSTS TO SERVE THE PROJECTED DATA CENTER LOAD BE DIRECTLY ASSIGNED TO DATA CENTER CUSTOMERS?

A37. The Commission's Scheduling Order in Case No. PUR-2024-00144 also raised the possibility of directly assigning transmission costs. Among the topics identified for discussion at the Technical Conference was a "line extension policy" and "whether certain transmission costs should be directly assigned to a new large-use customer class."

The current National Association of Regulatory Utility Commissioners' ("NARUC") Electric Utility Cost Allocation Manual[21] discusses the direct assignment of transmission costs on page 83 as follows:

> The costs of specific transmission facilities, such as long radial transmission lines and substations, may be directly assigned to particular customers. Direct assignments of such costs implies that the facilities can be considered entirely apart from the integrated system. In fact, the case for the independence of the facilities must be unequivocal since the customer must be willing to bear all the costs of service that, due to the unintegrated character of the facilities, may be just as high for service that is less reliable than service on the integrated system.

In the 2024 IRP Case, for all planned transmission line projects, the Commission directed Dominion to ***identify whether the need for the transmission project is primarily being driven by data center load growth***.

Dominion complied with this Commission directive and supplied the required information in Supplemental Appendix 2C-2 of Dominion's supplemental 2024 IRP filing.

[21] Staff Subcommittees on Electricity and Economics, National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual (1992).

Dominion identified a total cost of $7.595 billion for all planned transmission projects. Of this amount, $2.435 billion, or 32%, are transmission projects where the primary need driver for the project is to serve data center customers. Dominion also identified $3.329 billion, or 44%, of these transmission projects are partially driven by the need to serve data center customers.

On page 6 of Dominion's supplemental 2024 IRP filing, the Company states: "Data center driven projects are identified by a "Y" in the Data Center column and include projects that (1) were initiated by a Delivery Point ("DP") request specifically indicating that the interconnection was for a new data center load or, (2) resolve "harm" associated with the interconnection of new data center DPs, as identified through PJM and Transmission Owners' "Do No Harm" ("DNH") analysis."

The $3.329 billion of planned transmission lines that Dominion identified as partially driven to serve data center load are multi-driver regional reliability, mixed load (e.g., commercial, residential, and data center), and/or generation deliverability projects that have been awarded to the Company through PJM's competitive Regional Transmission Expansion Plan ("RTEP") process. These RTEP transmission projects are required to maintain the reliability of the entire PJM footprint taking into consideration data center load growth and power plant retirements. PJM allocates the costs of the RTEP projects to all zones in the PJM RTO using PJM's default methodology. Thus, these RTEP projects are not deemed by PJM to be solely driven to serve data center load growth in Virginia. Nevertheless, many of these RTEP transmission projects are primarily, but not solely, required due to data center load growth in Northern Virginia.

PJM also evaluates "Supplemental" transmission line projects. Supplemental Projects are transmission expansions or enhancements that are requested by the transmission owner to meet local needs. PJM performs a do no harm study to evaluate whether a proposed Supplemental Project will adversely impact the reliability of the Transmission System as represented in the planning models used in other PJM reliability planning studies. If as a result of the do no harm study, system upgrades are found to be required, such upgrades will be considered part of the Supplemental Project and are the responsibility of the Transmission Owner sponsoring the Supplemental Project. In other words, the costs of Supplemental Projects, including the costs of any required upstream reliability requirements, requested by Dominion to serve a large data center customer's load are 100% directly assigned to the DOM Zone by PJM. This means Supplemental Project costs are currently socialized among all LSEs, and presumably all ratepayers, in the DOM Zone.

Using the same logic as PJM, the Supplemental transmission projects identified by Dominion as being required to serve specific data centers should also be directly assigned to the data center(s) that require the Supplemental Project(s).[22] Thus, $2.435 billion of costs identified by Dominion as being primarily driven by data centers would be directly assigned to those data center customers. This can then be collected from the data center customer(s) up front as a CIAC or over some specified time period as an excess transmission facilities charge. Directly assigning these costs to the cost causer will prevent

[22] The costs of Supplemental Projects that are directly assigned to the DOM Zone are allocated to the load serving entities ("LSEs") in the DOM Zone using the FERC approved 12-CP methodology for the DOM Zone. The $2.435 billion of costs identified by Dominion is the share of these costs expected to be allocated to the Dominion LSE.

cost shifting to other customers and will also provide a strong incentive to prospective data center customers to provide accurate load estimates.[23]

If the Commission approved the direct assignment of these costs to the specific data centers causing the costs of the Supplemental Projects to be incurred (*i.e.* these costs would not be incurred but for the data centers)[24], then $2.435 billion of plant would then be removed from the calculation of the Rider T1 revenue requirement that is allocated to all customer classes using the 12-CP allocator.

I recommend that the Commission direct Dominion to directly assign the costs of Supplemental Projects that are solely needed to serve High Load data centers to those data center customers causing the costs. I further recommend that the Commission direct Dominion to develop terms and conditions to implement this direct assignment and submit the proposed language to the Commission for approval.

CLASS COST OF SERVICE

Q38. DID DOMINION EXAMINE ANY ALTERNATIVE CLASS COST OF SERVICE METHODOLOGIES IN LIGHT OF THE PROJECTED DATA CENTER LOAD?

A38. No. Dominion's response to PEC Interrogatory No. 4-31 states that: "While the Company consistently assesses the results of its cost allocation studies to ensure that its allocation

[23] In terms of both the impacts to reliability of the grid and the scope and costs of required system improvements, a proposed merchant plant seeking to inject power onto the transmission grid is analogous to a High Load data center customer seeking to draw peak power off of the grid. However, the costs of such grid improvements are directly assigned and collected up front from the merchant plant as CIAC whereas the costs of the grid improvements to serve the large data center customers are currently socialized and included in the Rider T1 rate base that is collected from all customers.

[24] Conceptually, these Supplemental Projects may be available to serve other customers but they are not needed to serve other customers. For example, in Case No. PUR-2024-00135, currently pending before the Commission, the Supplemental Project is solely needed to serve a large data center customer. The evidence showed that the load growth for the non-data center customers in the Van Dorn Load Area was flat. Absent the load demands of the data center customer, a rough ballpark estimate of the year when transmission improvements would be required to serve existing customers' load growth in the Van Dorn Load Area ranges from 2094 to 2113.

methodologies remain reasonable, it did not formally assess any alternative methodologies in connection with this proceeding."

It also appears that in lieu of exploring alternative CCOS methodologies, Dominion relied on the conclusion in the JLARC Study that "data centers are currently paying full cost of service." Several Dominion witnesses cite this statement from the JLARC Study. However, this JLARC conclusion is based on the cost recovery study performed by JLARC's energy consultant E3. It appears that the E3 Study limited its analysis to currently approved cost allocation methodologies for generation and transmission costs that it received after consultation with Dominion. The E3 Study did not evaluate alternative CCOS methodologies. Dominion justifying its methodology by relying on the JLARC Study that, in turn, relied on Dominion for the methodology creates a circular logic fallacy.

Dominion witness Wishart provides additional support for maintaining existing CCOS methodologies for transmission and generation costs. On page 18 of his direct testimony, he states: "By maintaining the current cost allocation methodology the Company is avoiding discriminatory rate making. I understand that the Company has used the Average and Excess ("A&E") method for allocating the cost of generation capacity and the 12 CP approach has been used to allocate transmission costs for many years. These methods are widely adopted nationwide." Further, on page 19 of his direct testimony, Mr. Wishart states: "Generally, changes to cost allocation methods should only be undertaken if foundational aspects of cost causation change, such as changing from summer to winter coincident peak demand."

Q39. SHOULD THE MAGNITUDE OF DOMINION'S PROJECTION OF DATA CENTER LOAD GROWTH QUALIFY AS POTENTIALLY CHANGING THE FOUNDATIONAL ASPECTS OF COST CAUSATION?

A39. It absolutely represents a fundamental change. The projected data center load is roiling the PJM capacity price market, causing massive transmission infrastructure to be built as part of PJM's RTEP process, creating new customers with loads in excess of the nameplate capacities of even the largest generating units at a single data center campus, and changing the load factor for the Dominion system as a whole to name a few of the impacts.

Among the players in the data center market are corporations that mostly have only came into existence in recent years[25] and are now among the largest corporations in the world in terms of market capitalization. These corporations and the technologies they have brought to the marketplace have literally transformed the world – changing the way business is conducted and the way we communicate and share information with each other. The development of AI promises even greater transformational changes to society. Against this backdrop, electric markets and utilities are not exempt from this transformational change with both the nature of electric load demand and power flows on the grid being impacted.

It is understandable that Dominion has taken the posture to not seek to change from doing things the way they have always been done. Nevertheless, in light of the incredible changes taking place as a result of data center load growth, it is reasonable to reexamine current CCOS methodologies to either reaffirm their efficacy or to identify whether a different methodology is a better fit under current and expected circumstances.

[25] For example, Microsoft (1975), Apple (1976), Amazon (1994), Google (1998), and Meta (2004).

Q40. CAN YOU CONFIRM THAT DOMINION'S A&E METHOD FOR ALLOCATING GENERATION COSTS AND 12-CP APPROACH FOR ALLOCATING TRANSMISSION COSTS HAVE BEEN USED FOR MANY YEARS?

A40. That is true for allocating generation costs. The A&E method has been used in every base rate case, biennial review, and A 6 generation rider proceeding for the Virginia jurisdiction since 1972.[26]

However, Dominion only recently changed its CCOS methodology for transmission costs from the 1-coincident peak ("1-CP") method to the 12-CP method. The Commission's Final Order in Dominion's 2020 Rider Tl case, Case No. PUR-2020-00084, directed the Company to provide a plan, in its 2021 Rider Tl filing, for moving from the 1-CP allocation methodology towards the 12-CP methodology, with the first step of that plan to be implemented in the rate year beginning September 1, 2021. The Company's plan for a three-year transition from a 1-CP to 12-CP allocation methodology was submitted in Dominion's 2021 Rider T1 case, Case No. PUR-2021-00102, and approved by the Commission's Final Order in that case. Dominion fully transitioned to the 12-CP methodology after its 2023 Rider T1 case.

So, contrary to Dominion witness Wishart's claim that the 12-CP approach has been used to allocate transmission costs for many years, the methodology has in fact recently changed. The change to the 12-CP method was approved just five years ago and fully implemented just two years ago.

I agree that a CCOS methodology that has been in use for many years should only be changed if there is a compelling reason to do so. However, such changes are not unheard

[26] Miller Direct at 8.

of and, although rare, the Commission has approved changes in long standing CCOS methodologies in other cases.

Q41. PLEASE PROVIDE ANOTHER EXAMPLE FROM A RECENT CASE WHERE THE COMMISSION APPROVED A CHANGE IN A LONG STANDING CCOS METHODOLOGY.

A41. The Commission approved a similar gradual transition away from Virginia Natural Gas's ("VNG's") long used CCOS methodology for its transmission accounts and its Mains allocator for distribution mains account in Case No. PUR-2022-00052 ("VNG 2022 Rate case"). The Commission approved a stipulation that set forth a gradual shift over VNG's next three base rate cases to transition from VNG's Dedicated Design Day Capacity ("DDDC") allocation method to the Peak & Average ("P&A") method. Specifically, the approved Stipulation stated as follows:

> The Company will petition for and support a transition to the P&A methodology for the purpose of separating jurisdictional costs and revenues and apportioning jurisdictional revenues among its jurisdictional rate classes over the next three base rate proceedings to facilitate a gradual movement of costs and revenues. The Company, in its next three base rate proceedings, will calculate its proposed revenue requirement by moving one-third toward the P&A methodology in each case. The allocation factors will be calculated in accordance with the table below:

ALLOCATION METHODOLOGY FOR FACTORS #

STEP 1 – NEXT BASE RATE CASE	2/3 DDDC PLUS 1/3 P&A
STEP 2 – SECOND BASE RATE CASE	1/3 DDDC PLUS 2/3 P&A
STEP 3- THIRD BASE RATE CASE	100% P&A FACTORS

 # Jurisdictional and class DDDC factors are to be developed as VNG proposed in the instant case and averaged with the P&A jurisdictional and class as developed in Attachment MAT-1 and MAT-3 of the pre-filed testimony of Marc A. Tufaro (50% DDDC allocator plus 50% throughput allocator.)

This is another recent example of the Commission approving a new CCOS methodology to replace an old existing CCOS methodology that had been in place for many years.

Q42. WHY DID THE COMMISSION APPROVE A PLAN TO TRANSITION AWAY FROM DOMINION'S HISTORIC CCOS METHODOLOGY FOR TRANSMISSION PLANT IN ITS 2020 RIDER T1 CASE?

A42. On April 24, 2019, pursuant to section 205 of the Federal Power Act, in FERC Docket Nos. ER19-1661-000 and ER-1661-001, Dominion submitted proposed tariff revisions to the PJM Open Access Transmission Tariff to change the calculation of Network Service Peak Load for transmission customers within the DOM Zone. Specifically, Dominion proposed a new 12-CP allocation. In those Dockets, Dominion successfully argued before FERC that a 12-CP methodology was a more appropriate methodology for allocating transmission costs to transmission customers in the DOM Zone in PJM than the 1-CP methodology.

In the FERC Dockets, Dominion argued that under the 1-CP regime, certain LSEs within the DOM Zone were able to accurately predict the single peak, shed load, and thus avoid some or all of their transmission cost responsibilities. The Company argued that a 12-CP allocator would reduce cost shifting and would result in a more stable cost allocation. Additionally, the Company argued that a 12-CP approach would "address the full range of operating realities of its system" and "is consistent with transmission planning and associated cost causation principles."[27]

The FERC approved Dominion's proposal and found that the 12-CP methodology would reduce cost shifting and would result in a more stable cost allocation. The FERC

[27] See Hearing Exhibit 8 in Case No. PUR-2020-00084, Boehnlein Direct testimony at 8-9.

also found that a 12-CP allocation methodology more accurately reflects how the Company plans its transmission system.

Despite the arguments that Dominion made before FERC to support its proposal to move from the 1-CP methodology to the 12-CP methodology for purposes of allocating transmission costs to the LSEs in the DOM Zone, the Company inexplicably argued in its 2020 Rider T1 case to maintain the 1-CP methodology for allocating transmission costs to its customer classes.

The Commission rejected Dominion's arguments in the 2020 Rider T1 case and approved the 12-CP methodology for Rider T1 to commence with the next Rider T1 filing. In the 2021 Rider T1 filing, the Commission approved Dominion's transition plan to move from the 1-CP to 12-CP methodology over three years. This gradual approach guards against sudden shifts in costs to the various customer rate classes.

Q43. DO YOU AGREE WITH THE CONTINUED USE OF THE 12-CP METHODOLOGY FOR ALLOCATING TRANSMISSION COSTS IN LIGHT OF DOMINION'S PROJECTED PEAK LOAD AND ENERGY SALES FORECAST FOR DATA CENTERS?

A43. Yes. I believe the 12-CP methodology should continue to be used to allocate transmission costs to the customer classes with one exception. I recommend that the costs for those Supplemental Project(s) that are solely required to serve data center customer(s) be directly assigned to the data center customer(s) causing the costs to be incurred. The costs of the Supplemental Projects that have been directly assigned should then be removed from the Rider T1 revenue requirement that is allocated to the customer classes using the 12-CP allocator. Direct assignment will prevent these Supplemental Project costs from being socialized through Rider T1 and shifted to other customer classes.

Even though the scope of recent RTEP transmission projects has added significant costs to recent Rider T1 revenue requirements, primarily driven by data center load growth, the 12-CP approach remains appropriate. The Rider T1 revenue requirements are higher as a result but the number of billing determinants is also higher due to data center customers' load. In other words, the Rider T1 revenue requirement is higher but it is spread out over more billing determinants. Further, when FERC and the Commission approved the change from a 1-CP to a 12-CP methodology, the latest phase of data center load growth was already underway. I do not see any reason to change the allocation methodology from the 12-CP method at the present time.

Q44. HAS THE A&E METHODOLOGY FOR ALLOCATING GENERATION COSTS BEEN CHALLENGED BEFORE?

A44. Dominion has used the A&E method to allocate generation costs for over 50 years. It has been challenged in other cases but, so far, the Commission has sanctioned its continued use for both generation base rates and for generation RACs. For example, in Case No. PUR-2019-00104 for approval of the US-3 RAC, the A&E methodology was challenged by Staff and Consumer Counsel. The Commission's Final Order in that case stated on pages 3-4: "The Commission is cognizant of, and has fully considered, the evidence and arguments raised by Consumer Counsel and Staff. However, based on the record in the instant proceeding, we find that it is reasonable for the Company to continue allocating costs of intermittent generation resources based on Factor 1." The Commission's Final Order also included the following footnote on page 4 that stated: "This finding does not preclude subsequent approval of other allocation methodologies. For example, as generation fleets serving Virginia evolve with higher penetrations of solar, wind, and other non-fossil-fueled resources, the Commission may review the issue of classification and cost allocation for generation resources in a future proceeding."

It is clear that the Commission values and assigns significant weight to the principle of continuity in ratemaking and is reluctant to change a CCOS methodology that has been used for many years. This is especially the case for Dominion's generation costs that have been allocated using the A&E method for over 50 years. However, it is also clear from the footnote that the Commission is open to the possibility of changing CCOS methodologies for Dominion's generation resources. The Commission has already demonstrated that it will change long standing CCOS methodologies in Dominion's 2020 Rider T1 case and in the VNG 2022 Rate case if the evidence supports a change.

Thus, the question in the current case is whether the enormous projected load growth for data centers and the concomitant changes to system load factor and usage patterns meets the threshold to warrant a change in methodology for generation resources.

Q45. PLEASE DISCUSS THE A&E ALLOCATION METHODOLOGY.

A45. The NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") discusses at least 16 embedded cost allocation methodologies for allocating production costs including the A&E method. The sheer number of different allocation methodologies presented in the NARUC Manual suggests that there is no one scientifically correct way to allocate generation costs. All of the cost allocation methodologies contained in the NARUC Manual are legitimate, and determining which method is the best fit for a given utility depends on the operational realities that the utility is faced with and the informed judgment of the regulatory body that regulates the utility.

The A&E method considers both the "average" energy use of a rate class and the "excess" over the average during the class's peak hour of use. Although it has an energy component, it is usually considered to be a peaking allocation method. The A&E method has historically been viewed by the Commission as a good fit for Dominion. For utilities with a wide diversity of customer classes with differing load factors, the A&E method appropriately recognizes and accounts for the differing cost causation impacts of low-load factor customer classes and high-load factor customer classes and the relative size of the classes. Dominion must procure capacity to meet the coincident summer peak demand. This has historically been driven by the air conditioning demands of the low-load factor residential customer class. Also, the residential class historically has generally been Dominion's largest rate class. Dominion meets this projected peak load through a combination of baseload, intermediate, and peaking generation resources. Since the residential customer class has a low load factor, historically this created significant excess capacity during off-peak hours and during the non-heating and non-cooling months. This idle capacity has to be paid for whether the units are running or not. Thus, high-load factor customers like large industrial customers that operate 24-hours a day are able to utilize the excess capacity that would otherwise be idle. The A&E method may make sense in this scenario. The residential class has more "excess" over its "average" use and gets assigned a relatively higher percentage of costs. The high-load factor industrial classes have little "excess" over their "average" use and are assigned a relatively lower percentage of costs. Thus, when additional high-load factor industrial baseload demand occurs, it pushes up the coincident peak but it also absorbs much of the excess capacity during the off-peak hours and this benefits the whole system. The A&E method recognizes this and essentially provides these high-load factor customers with a discount reflecting that a significant portion of their energy use occurs when there is slack in the system.

The A&E allocator is reasonable for a system with excess generating capacity and a high diversity of low-load factor and high-load factor customer classes. The A&E method is not a good fit for a system that does not have much excess capacity and that requires large investments in new generation plant. The magnitude of the projected data center load growth will also shrink the low-load factor residential class's share of total system load. A landscape of changing system load factors and size relationships among rate classes can undermine the reasonableness of the continued use of the A&E method.

Q46. ARE THERE ANY OTHER ALLOCATION METHODS THAT YOU BELIEVE MAY BE MORE APPROPRIATE FOR ALLOCATING DOMINION'S GENERATION COSTS?

A46. Yes. I believe the probability of dispatch ("POD") method is an especially good fit for Dominion as a result of the rapid data center load growth in its service territory. Secondarily, I believe the 12-CP method would be a better peaking allocator to use than the A&E allocator on a going forward basis in light of the projected data center load growth. There are pros and cons to both of these methods as there are to any allocation methodology.

Q47. PLEASE DISCUSS THE POD ALLOCATION METHODOLOGY.

A47. The POD cost allocation methodology assigns costs to each hour in the year based on the energy production of each generating unit. Essentially, it defines an hourly cost for each hour in the 8,760 hours in the year for each generating unit in the fleet. Thus, a peaking unit like a gas CT unit that is dispatched 100 hours a year would have all of its capital cost spread over those 100 hours weighted by MWh production in each hour. In contrast, a baseload nuclear unit, like Dominion's Surry units, would have its cost spread over the full 8,760 hours in the year less any downtime for refueling. These hourly costs are then allocated to each customer rate class based on the hourly load share for each class during each hour in the 8,760 hours in the year when each unit was generating energy. In this way, the POD approach assigns the cost for each generating unit to each class based on the hours when the unit is actually generating and the relative percentage of energy each class uses in that hour. Adding up all of the unit specific hourly costs by class for the year gives you the overall allocation of the generation fleet to the customer classes.

A legitimate criticism of the POD methodology is that it does not give any weight to the relative value of energy during system peaks versus off-peak hours. This can be addressed by determining the economic cost during each hour by dividing the PJM locational marginal price ("LMP") energy cost ($/MWh) for the hour by the average LMP hourly energy cost for the year and weighting the costs assigned to each hour accordingly.

Thus, for a peaking unit like a gas-fired CT that operates 100 hours per year, its cost is spread over the 100 hours but is weighted to assign more of the cost to the hours with the highest LMP prices. This will allocate relatively higher amounts to the highest peak hours. Thus, the low-load factor residential customer class will be assigned a greater share of the gas CT unit's costs both because the residential class uses a greater share of energy during these peak heating and cooling hours and because the hourly LMP price is usually much higher during those hours relative to the average LMP price.

The POD method is intuitively appealing because it assigns costs to customer classes for specific units based on the actual hourly energy output of the units in direct proportion to the customer classes that are actually consuming energy in those hours. Thus, it reflects the actual supply and demand realities (market values) that are occurring on Dominion's system for each hour of the year.

Q48. DOES DOMINION SUPPORT A POD APPROACH?

A48. Dominion did not consider any alternative CCOS methodologies, including POD, in this case for allocating generation costs. Nevertheless, on page 18 of Dominion witness Stuller's Direct testimony he states: "Market-based rates are inherently "fair," in that they are calculated using customers' actual energy usage at the actual rates in effect when that energy is consumed. The Company's proposed rate design tracks market-based rates closely."

Of course, in fairness, Mr. Stuller is speaking about Dominion's MBR proposal in his testimony and not generation cost allocation. Regardless, Mr. Stuller's basis for declaring "market-based rates are inherently fair" is the same logic that underpins a POD approach to generation cost allocation.

Q49. WHAT ARE THE IMPEDIMENTS TO ADOPTING A POD METHODOLOGY?

A49. Even though the POD method is discussed in the NARUC Manual, it has not been widely adopted nationwide primarily because the POD approach requires substantial input data and analysis requirements. Most utilities, especially in 1992 when the NARUC Manual was published, did not have the equipment deployed capable of collecting hourly meter data for all of their rate classes. However, AMI meters capable of measuring hourly loads were developed in the early 2000s. As these high-tech AMI meters came down in costs, many utilities, including Dominion, rolled out AMI meters for all customers. AMI meters, among other things, allow the utility to gather real-time hourly, and even sub-hourly, usage data for every customer in their system. Dominion has widely deployed AMI meters for all customer classes and has the capability to gather the hourly usage data for each customer class with a high degree of accuracy to enable a POD approach. Importantly, the cost of the AMI meters is a sunk cost. Dominion is not required to incur any additional costs for the metering data required to perform a POD cost allocation. However, even with the actual hourly data, the more granular nature of the POD approach requires a more intensive complex computation of the allocation factors.

The POD approach has only recently become feasible precisely because of the capabilities enabled by the high-tech data center corporations. Thus, these high-tech corporations are placing enormous peak load and energy sales demands on the electric grid while, at the same time, enabling a more modern approach to utility cost allocation.

An argument that the POD method should be discarded because it has not previously been widely adopted and/or because it is not the way we have always done things should be rejected. It is a modern methodology that reflects the modern high-tech world we are currently living in.

Q50. PLEASE DISCUSS THE 12-CP ALLOCATION METHODOLOGY.

A50. The 12-CP methodology is a peaking allocator that is based on the coincident peak hour of demand for each of the 12 months in a calendar year. It is simple to calculate. Each class's usage during the coincident peak hour of demand for each month is added up over the 12 calendar months. The allocation factor for each class is then calculated by taking the sum of each class's total usage over the 12 monthly peak hours divided by the sum of the system usage over the 12 monthly peak hours. A low-load factor customer class will have a larger share of usage during the coincident peak hour demands for the winter and summer months but this is balanced out by a relatively lower share of usage during the peak hour demands for the shoulder months. The 12-CP methodology is useful when a system does not have a large disparity between monthly peak demands for the summer and winter months' peaks relative to the shoulder months' peaks. Also, if the magnitude of the difference between the winter and summer months' peaks compared to the shoulder months' peaks is shrinking, or is projected to shrink, then the 12-CP method may be a good fit. When this occurs, the system load factor increases. A higher system load factor means there is not as much "excess" relative to "average" usage and this makes the A&E method less desirable relative to the 12-CP method.

The Company's projected increase in data center load will cause the Dominion system load factor to steadily increase over time from 63% in 2024 to 72% by 2039.[28] This will change the way Dominion performs its generation planning.

If the system load factor is low, then an increase in the summer coincident peak load caused by the air conditioning demands of the residential class may be best met by a low efficiency peaking CT unit that has lower upfront capital costs but relatively higher fuel and operating expenses. These units are most effective for meeting a relatively low number of peaking hours but they are not effective for generating large amounts of energy over many hours.

[28] This is based on Dominion's supplemental 2024 IRP filing. However, Dominion stated in its fourth quarter earnings call that an additional 40 GW of data center demand was at various stages of development. This would increase the projected system load factor significantly higher should it materialize.

However, when the system load factor is increasing, this indicates that more energy is required throughout the year. In that instance, a baseload unit (nuclear, gas-fired combined cycle) with higher upfront capital costs but low fuel and operating costs makes the most sense. These units are capable of generating energy around the clock. Coincidentally, the high-load factor data center customers likewise consume energy around the clock.

Dominion's projected data center load forecast and the projected impact on the system load factor will change the way Dominion plans its generation system. If Dominion's data center load forecast proves accurate, more baseload generation units will need to be added to the fleet to meet the energy needs of the system during all months of the year including the shoulder months. Thus, the 12-CP methodology will more accurately reflect how the Company plans its generation system going forward given the large, around the clock, energy demands of the projected data center load and the residential class's projected decreasing share of system peak load and energy sales.

Q51. HOW DO THE RESULTS OF THESE CCOS METHODOLOGIES DIFFER FOR THE ALLOCATION OF DOMINION'S GENERATION PLANT?

A51. I did not perform CCOS studies using the A&E, POD, and 12-CP methods in this case. However, Staff witness Watkins did present the results for several different CCOS allocation methodologies in his testimony in Dominion's 2023 Biennial Review case, Case No. PUR-2023-00101.[29] The tables found on page 34 of Mr. Watkins testimony display the results of five different methodologies. In addition to the A&E, POD, and 12-CP methods, he also shows the results for the Summer/Winter Peak & Average ("SWPA")

[29] Hearing Exhibit 42 in Case No. PUR-2023-00101.

method and the Base-Intermediate-Peak ("BIP") method. Mr. Watkins's tables from his 2023 Biennial Review testimony are reproduced below.

TABLE 8
Comparison of Allocation Methods
RORs at Current Rates
GENERATION

Class	A&E	SWPA	12-CP	BIP	POD
Residential	6.47%	9.75%	7.20%	10.54%	13.20%
GS-1	9.20%	9.48%	9.97%	9.80%	10.25%
GS-2	13.90%	13.04%	13.69%	13.04%	12.40%
GS-3	10.32%	7.57%	9.25%	7.09%	5.69%
GS-4	4.93%	1.58%	3.91%	0.93%	-0.37%
Churches	10.02%	13.13%	11.74%	14.16%	16.67%
Lights	3.30%	15.12%	116.23%	9.06%	3.44%
Total Jurisdictional	7.54%	7.54%	7.54%	7.54%	7.54%

TABLE 9
Comparison of Allocation Methods
Indexed RORs at Current Rates
GENERATION

Class	A&E	SWPA	12-CP	BIP	POD
Residential	86%	129%	96%	140%	175%
GS-1	122%	126%	132%	130%	136%
GS-2	184%	173%	182%	173%	165%
GS-3	137%	100%	123%	94%	76%
GS-4	65%	21%	52%	12%	-5%
Churches	133%	174%	156%	188%	221%
Lights	44%	201%	1542%	120%	46%
Total Jurisdictional	100%	100%	100%	100%	100%

The results for the 2025 Biennial Review would be based on more recent data and would produce somewhat different results. However, these CCOS results from the 2023 Biennial Review case are useful for comparing and contrasting the potential impacts of moving from the A&E methodology to the POD or 12-CP methodologies. The A&E methodology is the most unfavorable to the residential class and the most favorable to the GS-3 and GS-4 customer classes. Conversely, the POD methodology is the most favorable to the residential class and the most unfavorable to the GS-3 and GS-4 customer classes. In fact, under the POD methodology, the GS-4 customer class has a negative rate of return indicating that it is being subsidized by the other customer classes. The 12-CP method produces a middle ground between the A&E and POD methods. It is not as unfavorable to the residential class as the A&E method nor as favorable to the GS-3 and GS-4 customer classes. However, since it is a peaking methodology, the 12-CP results are closer to the A&E results than the POD results.

It is impossible to know, at this time, what the impact of carving out the High Load customers into the proposed GS-5 customer class would have had on the results for the GS-3 and GS-4 classes under any of these methodologies.

Q52. WHAT METHODOLOGY DO YOU RECOMMEND FOR THE ALLOCATION OF GENERATION COSTS IN LIGHT OF DOMINION'S PROJECTED PEAK LOAD AND ENERGY SALES FORECAST FOR DATA CENTERS?

A52. I recommend that the Commission direct Dominion to transition away from the A&E methodology to the POD methodology for allocating generation costs in future Biennial Reviews and generation RAC cases. I believe that the enormous projected load growth for data centers and the concomitant changes to system load factor and usage patterns meets the threshold to warrant a change in the CCOS methodology for generation resources.

Should the Commission determine that the POD method is overly burdensome for Dominion to implement, then I would offer the alternative recommendation to transition away from the A&E methodology to the 12-CP methodology for allocating generation costs in future Biennial Reviews and generation RAC cases.

A53. WHAT DO YOU RECOMMEND FOR A TRANSITION PERIOD?

A53. I recommend that the Commission direct Dominion to transition away from the A&E method to the POD method beginning with the Company's next Biennial Review filing and completing the transition over the next three Biennial Review filings. This is accomplished by developing an allocator weighted 66.7% A&E and 33.3% POD in the first Biennial Case, 33.3% A&E and 66.7% POD in the second Biennial Review filing, and 100% POD in the third Biennial Review filing. These allocation factors would be applicable to the allocation of generation costs in the respective Biennial Reviews and also should be used to allocate costs for all generation RACs. In other words, all generation resources in the fleet should be allocated using the same allocation methodology regardless of whether the generating units' costs are recovered through base rates or a RAC or Rider.

This recommendation to transition away from the A&E method is consistent with the transitions approved by the Commission in the 2020 Rider T1 case and the VNG 2022 Rate case. It recognizes the important rate principle of "gradualism" and will prevent any sudden shifts in cost allocation. Further, it will not have an impact on cost allocation in the current case but is meant to be applied on a going forward basis.

RECOVERING CAPACITY COSTS IN THE FUEL FACTOR

Q54. DO YOU HAVE ANY COMMENTS ON DOMINION'S PROPOSAL TO MOVE THE COST RECOVERY OF NET CAPACITY PURCHASES FROM BASE RATES TO THE FUEL FACTOR?

A54. Yes. The Company will recover these costs regardless of the vehicle used to collect them. However, the fuel factor collects these costs on a dollar-for-dollar basis in real time. Base rate recovery of these costs is on a lagged basis and, depending on Dominion's return on equity position in the Biennial Review, could result in no change to base rates if Dominion is found to be within its authorized range of returns. In other words, there could be enough revenues available under current base rates to recover the capacity costs.

My preference would be to leave the recovery of the net costs of capacity purchases from PJM in base rates. However, Appalachian Power Company ("APCo") currently recovers the net costs of capacity purchases through its fuel factor. Given this, I do not oppose Dominion's proposal to move these capacity costs to the fuel factor. However, I am opposed to Dominion's proposed cost allocation of these costs in the fuel factor.

Q55. WHAT IS DOMINION'S PROPOSED COST ALLOCATION FOR CAPACITY COSTS IN THE FUEL FACTOR?

A55. Dominion is proposing to allocate these costs using the A&E allocator to maintain consistency with how these costs are allocated in base rates. The fuel factor, however, is allocated using an energy allocator. In my opinion, if Dominion wants to treat these costs as "fuel" or "energy" expenses, then the capacity costs should be recovered on an energy basis consistent with all other fuel and energy costs recovered in the fuel factor. APCo allocates the costs of net capacity purchases on an energy basis in its fuel factor. Importantly, APCo does not allocate capacity costs using the 6-CP methodology for allocating generation plant in APCo's base rates. Dominion is attempting to maintain an allocator from base rates that essentially treats capacity costs akin to generation production plant. Dominion's proposed A&E allocation also suggests that Dominion's believes that capacity costs should be allocated more heavily to the low-load factor classes. This proposed allocation would suggest that Dominion believes the low-load factor classes are more responsible for capacity prices and the costs of capacity purchases from PJM.

This premise is refuted by the PJM Independent Market Monitor's findings in his June 3, 2025 "Analysis of the 2025/2026 RPM Base Residual Auction."[30] The Market Monitor concluded the following:

> The basic conclusion of this analysis is that ***data center load growth is the primary reason for recent and expected capacity market conditions***, including total forecast load growth, the tight supply and demand balance, and high prices. ***But for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the tight supply demand conditions, the high prices observed in the BRA for 2025/2026 or the high prices expected for the 2026/2027 and subsequent capacity auctions.*** Holding aside all the other issues raised by the MMU in parts A through F of this report, ***data center load by itself resulted in an increase in the 2025/2026 BRA revenues of $9,332,103,858 or 174.3 percent*** (Scenario 88). It is misleading to assert that the capacity market results are simply just a reflection of supply and demand. The current conditions are not the result of organic load growth. ***The current conditions in the capacity market are almost entirely the result of large load additions from data centers***, both actual historical and forecast. ***The growth in data center load and the expected future growth in data center load are unique and unprecedented and uncertain and require a different approach than simply asserting that it is just supply and demand***. Specifically, the results of Part G show that the level of data center demand projected in the 2024 load forecast from new data centers and growth from existing data centers (growth above embedded) that were used for the 2025/2026 BRA, had a very significant impact on capacity market conditions, illustrated by the prices in the 2025/2026 BRA. The results of Part G also show that the expected level of data center demand included in the 2025 PJM load forecast is expected to have a very significant impact on capacity market conditions and prices in the capacity market for the 2026/2027 and subsequent BRAs. (emphasis added)

The astronomical increase in PJM capacity prices is not due to the peaking rate classes such as the residential class. Instead, the Market Monitor lays the responsibility at the feet of the large-use hyperscale data centers with the unprecedented load growth pushing the peaks higher from the bottom up.

[30] Available at https://www.monitoringanalytics.com/reports/reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf

I would particularly draw attention to the Market Monitor statement that: "The growth in data center load and the expected future growth in data center load are unique and unprecedented and uncertain and require a different approach than simply asserting that it is just supply and demand." This statement provides further support that the data center load growth meets the threshold to change the generation CCOS methodology for base rates.

Q56. WHAT IS YOUR RECOMMENDATION FOR NET CAPACITY COSTS?

A56. I am not opposed to Dominion's proposal to move cost recovery to the fuel factor, but I recommend that these costs be allocated to the customer classes using an energy allocator. If Dominion wishes to allocate these costs in the same manner as generation plant in base rates, then I recommend that these capacity costs remain in base rates for cost recovery.

SUMMARY OF RECOMMENDATIONS

Q57. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A57. This is a case of first impression. This is the first opportunity for the Commission to wrestle with cost allocation, rate design and terms and conditions in a very new and immersive environment due to the scope and scale of one group of energy users driving the size and design of the generation and transmission systems. PEC believes that we are entering into a new and different environment that requires a new and different approach than the old model. The table below summarizes PEC's recommendations for proposed GS-5 High Load customers and for capacity cost recovery compared to Dominion's proposal for each issue.

Issue	Dominion Proposed	PEC Recommendation
Minimum Charges	85% of Trans. and Dist. Demand Charges 60% of Generation Demand Charges	90% of Trans. and Dist. Demand Charges 90% of Generation Demand Charges
Reassignment of Capacity	20% Reduction at Customer Discretion 30% Reduction at Dominion's Discretion	10% Reduction at Customer Discretion 30% Reduction at Dominion's Discretion Require Dominion to Notify Commission of any Reductions to High Load Customers' Contract Capacity.
Contract Term	14 Years Total With a 4-Year Ramp Period	20 Years Total With a 3-Year Ramp Period
Ramp Rate	20% Per Year	40% Year 1, then 20% Per Year
Line Extension / Direct Assignment	N/A	Direct Assignment of Supplemental Transmission Project(s) to High Load Customer(s) Require Dominion to Propose and Submit a Tranmission Line Extension Policy for Commission Approval
Class Cost of Service	No Change in Current Methodology Proposed GS-5 Class to Track Cost Causation in the Future	No Change in Current Methodology for Dist. And Trans. Change to Probability of Dispatch ("POD") for Generation Transition to POD Over Next Three Biennial Reviews
Recovery of Capacity Costs	Move Recovery of Capacity Costs from Base Rates Into Fuel Factor. Allocate Capacity Costs using the A&E Methodology	Move Recovery of Capacity Costs from Base Rates Into Fuel Factor. Allocate Capacity Costs Using the Fuel Factor Energy Allocator

Q58. DOES THIS CONCLUDE YOUR TESTIMONY?

A58. Yes.

Gregory Abbott Testimonies/Reports

Proceeding	Case/Docket No.	On Behalf of:
Dale Service Corporation For General Increase in Rates	Virginia SCC Case No. PUE-2001-00200	Virginia SCC Staff
CPV Cunningham Creek LLC For Approval of a Generation Certificate	Virginia SCC Case No. PUE-2001-00477	Virginia SCC Staff
CPV Warren LLC For Approval of a Generation Certificate	Virginia SCC Case No. PUE-2002-00075	Virginia SCC Staff
Dale Service Corporation For Review of Changes to Terms and Conditions	Virginia SCC Case No. PUE-2002-00092	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of a Weather Normalization Adjustment Rider	Virginia SCC Case No. PUE-2002-00237	Virginia SCC Staff
Virginia-American Water Company For General Increase in Rates	Virginia SCC Case No. PUE-2002-00375	Virginia SCC Staff
Community Electric Cooperative For Approval of Retail Access Tariffs and Terms and Conditions of Service for Retail Access	Virginia SCC Case No. PUE-2003-00007	Virginia SCC Staff
A&N Electric Cooperative For Review of Tariffs and Terms and Conditions of Service for Retail Service	Virginia SCC Case No. PUE-2003-00279	Virginia SCC Staff
Central Virginia Electric Cooperative For Approval of Its Plan to Implement Retail Access	Virginia SCC Case No. PUE-2003-00327	Virginia SCC Staff
Atmos Energy Corporation For an Increase in Rates	Virginia SCC Case No. PUE-2003-00507	Virginia SCC Staff
Virginia-American Water Company For General Increase in Rates	Virginia SCC Case No. PUE-2003-00539	Virginia SCC Staff
Washington Gas Light Company For Approval of an Experimental Weather Normalization Adjustment	Virginia SCC Case No. PUE-2001-00010	Virginia SCC Staff
Craig-Botetourt Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case No. PUE-2005-00012	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of a Performance Based Rate Regulation Methodology	Virginia SCC Case No. PUE-2005-00057	Virginia SCC Staff

Virginia Natural Gas, Inc. For Investigation of Justness and Reasonableness of Current Rates, Charges, and Terms and Conditions of Service	Virginia SCC Case No. PUE-2005-00062	Virginia SCC Staff
Roanoke Gas Company For and Expedited Increase in Rates	Virginia SCC Case. No. PUE-2005-00075	Virginia SCC Staff
Highland New Wind Development, LLC For Approval to Construct, Own and Operate an Electric Generation Facility	Virginia SCC Case. No. PUE-2005-00101	Virginia SCC Staff
Dale Service Corporation For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2006-00070	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of an Experimental Weather Normalization Adjustment for General Service Customers	Virginia SCC Case. No. PUE-2006-00095	Virginia SCC Staff
Roanoke Gas Company For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2006-00099	Virginia SCC Staff
CPV Warren, LLC For Approval of a Generation Certificate	Virginia SCC Case. No. PUE-2007-00018	Virginia SCC Staff
Appalachian Power Company For Adjustment to Capped Electric Rates	Virginia SCC Case. No. PUE-2007-00069	Virginia SCC Staff
Old Dominion Electric Coop. & Columbia Gas of Virginia For Approval of a Certificate to Acquire Ownership Interest	Virginia SCC Case. No. PUE-2007-00088	Virginia SCC Staff
James River Cogeneration Company For a Certificate to Operate as an Electric Generating Facility	Virginia SCC Case. No. PUE-2007-00092	Virginia SCC Staff
Spectra Energy Virginia Pipeline Co. For Cancellation of Certificates	Virginia SCC Case. No. PUE-2007-00106	Virginia SCC Staff
Appalachian Power Company For Approval to Participate in the Virginia Renewable Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2008-00003	Virginia SCC Staff
Atmos Energy Corporation For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2008-00007	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Generation Certificate	Virginia SCC Case. No. PUE-2008-00014	Virginia SCC Staff
Columbia Gas of Virginia, Inc. For Approval of an Experimental Weather Normalization Adjustment Mechanism	Virginia SCC Case. No. PUE-2008-00074	Virginia SCC Staff

Roanoke Gas Company For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2008-00088	Virginia SCC Staff
Mecklenburg Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case. No. PUE-2009-00006	Virginia SCC Staff
Virginia Electric and Power Company For Approval of Annual Filing of Rider S	Virginia SCC Case. No. PUE-2000-00011	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Rate Adjustment Clause for Recovery of the Costs of the Bear Garden Generating Station	Virginia SCC Case. No. PUE-2009-00017	Virginia SCC Staff
Washington Gas Light Company For Approval of Natural Gas Conservation and Ratemaking Efficiency Plan including a Decoupling Mechanism	Virginia SCC Case. No. PUE-2009-00064	Virginia SCC Staff
Craig-Botetourt Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case. No. PUE-2009-00065	Virginia SCC Staff
Appalachian Power Company For Approval of Purchase Power Agreements as Part of Its Participation in the Virginia Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2009-00102	Virginia SCC Staff
Columbia Gas of Virginia, Inc. For Authority to Increase Rates and Charges and to Revise the Terms and Conditions	Virginia SCC Case. No. PUE-2010-00017	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Continue Two Rate Adjustment Clauses, Riders C1 and C2	Virginia SCC Case. No. PUE-2010-00084	Virginia SCC Staff
Appalachian Power Company Proposed Pilot Programs on Dynamic Rate Structures for Renewable Generation Facilities	Virginia SCC Case. No. PUE-2010-00134	Virginia SCC Staff
Virginia Natural Gas, Inc. For an Increase in Base Rates and Authority to Revise the Terms and Conditions	Virginia SCC Case. No. PUE-2010-00142	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish an Electric Vehicle Pilot Program	Virginia SCC Case. No. PUE-2011-00014	Virginia SCC Staff
Appalachian Power Company For Approval of a Rate Adjustment Clause, RPS-RAC, to Recover the Incremental Costs of Participation in the Virginia Renewable Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2010-00034	Virginia SCC Staff

Virginia Electric and Power Company For Approval to Implement New Demand-Side Management Programs and For Approval of Two Updated Rate Adjustment Clauses	Virginia SCC Case. No. PUE-2011-00093	Virginia SCC Staff
Virginia-American Water Company For a General Increase in Rates	Virginia SCC Case. No. PUE-2011-00127	Virginia SCC Staff
Virginia Electric and Power Company To Revise a Rate Adjustment Clause: Rider R	Virginia SCC Case. No. PUE-2012-00068	Virginia SCC Staff
Virginia Electric and Power Company For Revision of Rate Adjustment Clause: Rider B	Virginia SCC Case. No. PUE-2012-00072	Virginia SCC Staff
Appalachian Power Company For Approval of the Recovery of Incremental Costs of Participation in the Renewable Energy Portfolio Program	Virginia SCC Case. No. PUE-2012-00094	Virginia SCC Staff
Virginia Electric and Power Company For Approval & Certification of Proposed Brunswick Co. Power Station	Virginia SCC Case. No. PUE-2012-00128	Virginia SCC Staff
Atmos Energy Corporation For Approval of a Special Contract for Gas Transportation Service	Virginia SCC Case. No. PUE-2013-00038	Virginia SCC Staff
Northern Virginia Electric Cooperative For Approval of Pole Attachment Rates and Terms and Conditions	Virginia SCC Case. No. PUE-2013-00055	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2013-00088	Virginia SCC Staff
Virginia Electric and Power Company For Revision of Rate Adjustment Clause: Rider BW	Virginia SCC Case. No. PUE-2013-00122	Virginia SCC Staff
Appalachian Power Company Petition for Approval of Rate Adjustment Clause	Virginia SCC Case. No. PUE-2014-00007	Virginia SCC Staff
Appalachian Power Company Application for a 2014 Biennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services	Virginia SCC Case. No. PUE-2014-00026	Virginia SCC Staff
Virginia Electric and Power Company For Establishment of a Rate Adjustment Clause: Rider U, New Underground Distribution Facilities	Virginia SCC Case. No. PUE-2014-00089	Virginia SCC Staff
Appalachian Power Company Petition for Approval of Rate Adjustment Clause Related to its Participation in the Renewable Portfolio Energy Portfolio Program	Virginia SCC Case. No. PUE-2015-00034	Virginia SCC Staff

Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2015-00035	Virginia SCC Staff
Washington Gas Light Company Application for Approval of a Natural Gas Supply Investment Plan	Virginia SCC Case. No. PUE-2015-00055	Virginia SCC Staff
Virginia Electric and Power Company For Approval of Special Rates, Terms and Conditions	Virginia SCC Case. No. PUE-2015-00103	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish Experimental Companion Rates Designated Rate Schedule MBR - GS-3 and Rate Schedule MBR - GS-4	Virginia SCC Case. No. PUE-2015-00108	Virginia SCC Staff
Virginia Electric and Power Company For Establishment of a Rate Adjustment Clause: Rider U, New Underground Distribution Facilities	Virginia SCC Case. No. PUE-2015-00114	Virginia SCC Staff
Atmos Energy Corporation Application for Expedited Approval of a Special Contract for Gas Transportation Service	Virginia SCC Case. No. PUE-2015-00125	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2016-00049	Virginia SCC Staff
Appalachian Power Company For Approval of a Rate Adjustment Clause	Virginia SCC Case. No. PUE-2016-00090	Virginia SCC Staff
Virginia Electric and Power Company For Revision of a Rate Adjustment Clause: Rider U	Virginia SCC Case. No. PUE-2016-00136	Virginia SCC Staff
Appalachian Power Company For Approval of a Wind G Rate Adjustment Clause	Virginia SCC Case. No. PUR-2017-00031	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2017-00051	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish Experimental Companion Tariff, Designated Schedule RF	Virginia SCC Case. No. PUR-2017-00137	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2018-00065	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Rate Adjustment Clause, Designated Rider E	Virginia SCC Case. No. PUR-2018-00195	Virginia SCC Staff
Virginia Electric and Power Company For Approval & Certification of Proposed US-3 Solar Projects and for Approval of a Rate Adjustment Clause, Designated Rider US-3	Virginia SCC Case. No. PUR-2018-00101	Virginia SCC Staff

Virginia Electric and Power Company For Prudency Determination with Respect to the Coastal Virginia Offshore Wind Project	Virginia SCC Case. No. PUR-2018-00121	Virginia SCC Staff
Virginia Electric and Power Company For Revision of Rate Adjustment Clause: Rider US-3	Virginia SCC Case. No. PUR-2019-00104	Virginia SCC Staff
Virginia Electric and Power Company For Approval & Certification of Proposed US-4 Solar Projects and for Approval of a Rate Adjustment Clause, Designated Rider US-4	Virginia SCC Case. No. PUR-2019-00105	Virginia SCC Staff
Virginia Electric and Power Company For a Prudency Determination with Respect to the Westmoreland Solar Power Purchase Agreement	Virginia SCC Case. No. PUR-2019-00133	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2020-00035	Virginia SCC Staff
Virginia Electric and Power Company Establishing 2020 RPS Proceeding	Virginia SCC Case. No. PUR-2020-00134	Virginia SCC Staff
Appalachian Power Company Establishing 2020 RPS Proceeding	Virginia SCC Case. No. PUR-2020-00135	Virginia SCC Staff
Virginia Electric and Power Company Allocating RPS Costs to Certain Customers of Virginia Electric and Power Company	Virginia SCC Case. No. PUR-2020-00164	Virginia SCC Staff
Virginia Electric and Power Company To Revise Its Fuel Factor	Virginia SCC Case. No. PUR-2022-00064	Appalachian Voices
Appalachian Power Company 2022 Integrated Resource Plan Filing	Virginia SCC Case. No. PUR-2022-00051	Appalachian Voices
Roanoke Gas Company For an Expedited Rate Increase	Virginia SCC Case. No. PUR-2022-00205	Roanoke Gas Company
Virginia Electric and Power Company For Approval of its 2022 RPS Development Plan	Virginia SCC Case. No. PUR-2022-00124	Appalachian Voices
Virginia Electric and Power Company For Reinstatement and Revision of a Rate Adjustment Clause Designated Rider RGGI	Virginia SCC Case. No. PUR-2023-00070	Appalachian Voices
Appalachian Power Company For Triennial Rate Review	Virginia SCC Case. No. PUR-2023-00002	Appalachian Voices
Virginia Electric and Power Company 2023 Integrated Resource Plan Filing	Virginia SCC Case. No. PUR-2023-00066	Appalachian Voices
Virginia Electric and Power Company For Approval of its 2023 RPS Development Plan	Virginia SCC Case. No. PUR-2023-00142	Appalachian Voices
Roanoke Gas Company For Approval of a General Rate Increase	Virginia SCC Case. No. PUR-2024-00006	Roanoke Gas Company

Appalachian Power Company For Biennial Rate Review	Virginia SCC Case. No. PUR-2024-00024	Appalachian Voices
Virginia Electric and Power Company For Approval of rate adjustment clause designated Rider GEN	Virginia SCC Case. No. PUR-2024-00097	Appalachian Voices
Virginia Electric and Power Company For Approval and Certification of Electric Transmission Facilities	Virginia SCC Case. No. PUR-2024-00135	ReisingerGoochPLC
Virginia Electric and Power Company For Approval of its 2024 RPS Development Plan	Virginia SCC Case. No. PUR-2024-00147	Appalachian Voices

Attachment GLA-2

(Company Responses to PEC Set 1-11, PEC Set 1-16, and PEC 4-31)

Virginia Electric and Power Company
Case No. PUR-2025-00058
Piedmont Environmental Council
First Set

The following response to Question No. 11 of the First Set of Interrogatories and Requests for Production of Documents propounded by Piedmont Environmental Council received on April 25, 2025, was prepared by or under the supervision of:

Jen Kostyniuk
Senior Policy Director – Economic Development
Dominion Energy Virginia

Question No. 11

Please reference page 5 of Dominion Witness Blackwell’s direct testimony that indicates that the majority of new data center requests are for 300 MW campuses and that Dominion has also received requests in the 2,400 to 7,000 MW range. In the last five years has Dominion received any load letters from non-data center customers for a load of 300 MW or more?

Response:

No. Over the past five years the Company has not received any load letters from non-data center customers for a load of 300 MW or more.

Virginia Electric and Power Company
Case No. PUR-2025-00058
Piedmont Environmental Council
First Set

The following response to subparts (h), to Question No. 16 of the First Set of Interrogatories and Requests for Production of Documents propounded by Piedmont Environmental Council received on April 25, 2025, was prepared by or under the supervision of:

Stan Blackwell
Director – Data Center Practice
Dominion Energy Virginia

The following response to subparts to subparts (a)-(f) and (j)-(k) to Question No. 16 of the First Set of Interrogatories and Requests for Production of Documents propounded by Piedmont Environmental Council received on April 25, 2025, was prepared by or under the supervision of:

Joseph L. Bocanegra
Manager, Sales and Revenue
Dominion Energy Services, Inc.

As it pertains to legal issues, the following response to Question No. 16 of the First Set of Interrogatories and Requests for Production of Documents propounded by Piedmont Environmental Council received on April 25, 2025, was prepared by or under the supervision of:

Timothy D. Patterson
McGuireWoods LLP

Question No. 16

Please reference the table on Data Center Metrics on page 5 of Dominion Witness Blackwell's direct testimony. Please provide the following:

(a) The Virginia jurisdictional load factor for Dominion for 2013, 2020, and 2024;

(b) The load factor for data center customers for 2013, 2020 and 2024;

(c) The load factor for non-data center customers for 2013, 2020 and 2024;

(d) Based on Dominion's 2024 IRP load forecasts, please provide the projected Virginia jurisdictional load factor for 2030, 2035, and 2040;

(e) Based on Dominion's 2024 IRP load forecasts, please provide the projected load factor for data center customers only for 2030, 2035, and 2040;

(f) Based on Dominion's 2024 IRP load forecasts, please provide the projected load factor for non-data center customers for 2030, 2035, and 2040;

(g) The Virginia jurisdictional baseload demand (minimum hourly demand) for 2013, 2020, and 2024;

(h) The baseload demand for data center customers only for 2013, 2020, and 2024;

(i) The baseload demand for non-data center customers for 2013, 2020, and 2024;

(j) Based on Dominion's 2024 IRP load forecasts, please provide the projected Virginia jurisdictional baseload demand for 2030, 2035, and 2040;

(k) Based on Dominion's 2024 IRP load forecasts, please provide the projected baseload demand for data center customers only for 2030, 2035, and 2040;

(l) Based on Dominion's 2024 IRP load forecasts, please provide the projected baseload demand for non-data center customers for 2030, 2035, and 2040.

Response:

(a) The Company objects to this request as it would require original work. The Company does not estimate Virginia jurisdictional load at a system level.

(b) For DOM LSE, DOM data center, and DOM LSE less data center estimated annual load factor please see the table below:

	2013	2020	2024
DOM LSE LF	N/A	57%	59%
Data Center LF	N/A	85%	95%
DOM LSE Less DC LF	N/A	54%	52%

(c) Please see the table provided in the Company's response to subpart (b) of this question.

(d) The Company does not disaggregate its IRP forecast to the Virginia jurisdictional level for the IRP.

(e) Please see Attachment PEC Set 01-16 (JLB) for the requested annual load factor.

(f) Please see Attachment PEC Set 01-16 (JLB) for the requested annual load factor.

(g) The Company objects to this request on the ground that the term "baseload demand" is vague and undefined.

(h) The Company objects to this request on the ground that the term "baseload demand" is vague and undefined. Notwithstanding and subject to this objection, the Company responds to this request assuming that "baseload demand" means billing demand. Please see the table below:

Total Billed Demand (MW)	
Year	**MW**
2013A	462
2020A	1,808
2024A	3,581
2030P	7,041
2035P	10,291
2040P	14,858

(i) The Company objects to this request on the ground that the term "baseload demand" is vague and undefined.

(j) The Company does not disaggregate its IRP forecast to the Virginia jurisdictional level for the IRP.

(k) The Company objects to this request on the ground that the term "baseload demand" is vague and undefined. Notwithstanding and subject to this objection, the Company responds to this request assuming that "baseload demand" means forecasted monthly load. Please see Attachment PEC Set 01-16 (JLB) for the requested information.

(l) The Company objects to this request on the ground that the term "baseload demand" is vague and undefined. Notwithstanding and subject to this objection, the Company responds to this request assuming that "baseload demand" means forecasted monthly load. Please see Attachment PEC Set 01-16 (JLB) for the requested information.

Virginia Electric and Power Company
Case No. PUR-2025-00058
Piedmont Environmental Council
Fourth Set

The following response to Question No. 31 of the Fourth Set of Interrogatories and Requests for Production of Documents propounded by Piedmont Environmental Council received on June 5, 2025, was prepared by or under the supervision of:

Robert E. Miller
Manager – Regulation
Virginia Electric and Power Company

Question No. 31

The load forecast contained in Dominion's 2024 IRP is primarily driven by High Load data center customers. Given that this new load will shift usage patterns and system load factors, did Dominion perform any analysis or give any consideration to alternative class cost of service (CCOS) methodologies (12-CP, probability of dispatch, etc.) for generation plant? Please provide any analysis performed of alternative CCOS methodologies and indicate how Dominion determined the A&E allocation methodology remains the best fit for allocating generation plant costs on a going forward basis.

Response:

The Company believes that the Average and Excess ("A&E") allocation methodology continues to appropriately allocate generation demand-related costs among the Virginia jurisdictional customer classes, and that it is responsive to changes in the nature of customers and the costs that these customers cause to be incurred. While the Company consistently assesses the results of its cost allocation studies to ensure that its allocation methodologies remain reasonable, it did not formally assess any alternative methodologies in connection with this proceeding.

CERTIFICATE OF SERVICE

I, William T. Reisinger, hereby certify that a true copy of the foregoing was served on July 16, 2025, by e-mail to:

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