Appalachian Mountain Advocates

6101 Penn Avenue, Suite No. 201
Pittsburgh, Pennsylvania 15206
Telephone: (434) 738 – 1863

www.appalmad.org

February 28, 2025

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Mr. Bernard Logan, Clerk
c/o Document Control Center
STATE CORPORATION COMMISSION
Tyler Building — First Floor
1300 East Main Street
Richmond, Virginia 23219

RE: Commonwealth *ex rel.* State Corporation Commission, *In re*: Virginia Electric & Power Company's Integrated Resource Plan filing pursuant to Virginia Code § 56-597 et seq.

Case No. PUR-2024-00184

Dear Mr. Logan,

Please find attached for filing in the above-captioned case the following testimony, in public version only, on behalf of the Sierra Club and the Natural Resources Defense Council:

- Direct Testimony of Devi Glick
- Direct Testimony of William M. Shobe

Please do not hesitate to contact me if you have any questions regarding these filings.

Thank you,

Evan D Johns

Evan Dimond Johns
APPALACHIAN MOUNTAIN ADVOCATES
6101 Penn Avenue, Suite No. 402
Pittsburgh, Pennsylvania 15206
Phone: (434) 738 – 1863
E-Mail: ejohns@appalmad.org

Copied by Electronic Mail:

Commission Staff
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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, *ex rel.*

STATE CORPORATION COMMISSION

In re: Virginia Electric and Power Company's 2024 Integrated Resource Plan filing pursuant to Virginia Code § 56-597 *et seq*.

Case No. PUR-2024-00184

DIRECT TESTIMONY of

DEVI GLICK

ON BEHALF OF

SIERRA CLUB & NATURAL RESOURCES DEFENSE COUNCIL

February 28, 2025

Summary of the Direct Testimony of Devi Glick

Dominion's 2024 Integrated Resource Plan presents the Company's plan to address the dramatic data center load growth that it expects to see over the next few decades. This load growth, coupled with Dominion's ongoing need to meet the resource and generation requirements of the Virginia Clean Energy Act (VCEA) are the main drivers of the results Dominion presents in its 2024 IRP.

Dominion modeled four base scenarios that all include data center growth, two sensitivities with relaxed build limits, and supplemental scenarios without data center load. The data center growth increased the portfolio net present value revenue requirement (NPVRR) by $22.1 billion (relative to no data centers), delayed all previously planned retirements and drove the addition of 3.4 GW of new gas capacity, 1.3 GW of small modular reactor (SMR) capacity, 1.8 GW of battery energy storage systems (BESS), and 3.4 GW of offshore wind. In scenarios both with and without data center load, Dominion's model builds 12.2 GW of solar photovoltaics (solar PV), demonstrating it is the lowest cost energy option regardless of load growth levels.

I model two Dominion base scenarios (with and without data center load) and a Synapse Alternative Scenario that meets Dominion's data center load with increased levels of energy efficiency (EE), renewables, and long-duration energy storage (LDES). I find that with increased access to renewables, ratepayer costs go down by around $1 billion over the next 15 years, carbon emissions fall, additional storage is deployed, and no SMRs are built.

I recommend that the Commission require Dominion to revise its 2024 IRP and update its modeling by (1) lifting or easing the build limits it has placed on solar PV and battery storage; (2) modeling increased EE investment consistent with statutory requirements; and (3) adding LDES as a resource option. I also recommend that the Commission require Dominion to develop alternative tariff options for data center customers that address both risk and enable deployment of increased renewable energy. Dominion should require data center commitment to an alternative tariff as a pre-condition for modeling near-term new data center load (over the next five years) and should evaluate revenue requirement and bill impacts of the new load with alternative tariff structures in place. Dominion should also conduct a study to clearly identify the incremental gas infrastructure and how much of the incremental $22.4 billion in transmission costs are attributed to data center load.

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1. INTRODUCTION & PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc. (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in over 60 litigated proceedings across 20 states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than 12 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Sierra Club and the Natural Resources Defense Council.

Q Have you testified before the State Corporation Commission of Virginia?

A Yes, I submitted testimony in Case No. PUR-2023-00066, Case No. PUR-2023-00005, Case No. PUR-2022-00006, and Case No. PUR-2018-00195—all dockets related to Dominion resource planning or environmental compliance investments. I also submitted testimony in Case No. PUR-2022-00051, Appalachian Power Company's Integrated Resource Planning (IRP) docket.

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

A In this proceeding, I review Dominion's 2024 Integrated Resource Plan (2024 IRP) and evaluate its final portfolios, modeling methodology, and input assumptions. I then present the results of Synapse's alternative analysis. Synapse's EPA and VCEA compliant alternative scenario meets the energy needs of the Company's high load forecast and complies with current state and federal requirements while building more renewables and battery storage resources, increasing investment in energy efficiency, emitting less carbon dioxide (CO_2), and resulting in a lower cost to ratepayers than Dominion's portfolios.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I summarize Dominion's resource plan modeling framework, replacement resources considered, and modeling results.

In Section 4, I present the results of Synapse's alternative analysis. I describe our modeling tool and its capabilities. I describe the scenarios and sensitivities we modeled and outline our input assumptions with a focus on where our assumptions aligned with Dominion's and where they differed. I present the results of Synapse's modeling and show how our results compare to the results the Company presented. I explain the drivers of the differences between Synapse's modeling results and Dominion's.

In Section 5, I provide more context and detail on the challenging issues facing Dominion in this IRP: these include the risk and cost to existing ratepayers of building to meet data center load growth, regulatory and fuel price volatility risks from continued reliance on fossil resources, and the cost of incremental firm gas and transmission required to support the data center build-out

In Section 6, I outline strategies the Commission can take to protect non-data center ratepayers from the costs and risks imposed by the data center load.

Q What information do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily on the workpapers, exhibits, and discovery responses of Dominion's witnesses. I also rely on other publicly available documents and data, which I cite throughout my testimony.

Q Are you sponsoring any exhibits?

A Yes. I am sponsoring the following exhibits:

Exhibit No.	Description of Exhibit
Exhibit DG-1	Resume of Devi Glick
Exhibit DG-2	Company's Response to Commission Staff Discovery Request No. 2-70
Exhibit DG-3	Company's Response to Commission Staff Discovery Request No. 9-180
Exhibit DG-4	Company's Response to Commission Staff Discovery Request No. 8-164
Exhibit DG-5	Company's Response to Commission Staff Discovery Request No. 3-86
Exhibit DG-6	Company's Supplemental Response to Staff Discovery Request No. 8-170
Exhibit DG-7	Company's Response to Commission Staff Discovery Request No. 1-41

Exhibit No.	Description of Exhibit
Exhibit DG-8	Company's Response to Sierra Club Discovery Request No. 1-22(b)
Exhibit DG-9	Company's Response to Sierra Club Discovery Request No. 1-22, Attachment 1-22(c)
Exhibit DG-10	Company's Response to Commission Staff Discovery Request No. 7-154(k)
Exhibit DG-11	Company's Response to Commission Staff Discovery Request No. 3-100
Exhibit DG-12	Company's Response to Clean Virginia Discovery Request No. 2-2
Exhibit DG-13	Company's Response to Commission Staff Discovery Request No. 5-134(e)

2. FINDINGS & RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. Dominion's projections around data center load growth are driving Dominion to (1) maintain its existing Clover, Mount Storm, and Virginia City Hybrid Energy Center (VCHEC) coal-fired plants; (2) maintain the majority of its existing gas plants throughout the entire 15-year planning period; and (3) build over 20 GW of new generation resources on its system (27 GW including PPAs) across all portfolios.

2. The new resources that Dominion builds to serve data center load add $22.1 billion to the NPVRR of Dominion's portfolios relative to the portfolios without data centers.

3. Dominion's renewable portfolio standard (RPS) requirements under the VCEA grow as its load grows. To meet this requirement, in all its alternative

portfolios, Dominion must build a substantial quantity of new renewables, or else pay a large RPS compliance penalty.

4. Dominion imposed strict build limits on the quantity of solar photovoltaics (PV), wind, and battery storage that the model was allowed to select in each year and did not justify this constraint with any data or analysis. As a result of these limitations, the model maxed out the amount of solar PV that it was allowed to add starting in 2029, and the amount of battery storage it was allowed to add starting in 2030 across all four base scenarios.

5. Dominion is not planning sufficient EE investment to comply with state EE requirements, including those recently established under Virginia Code § 5-596.2 B 3. Investment in incremental EE will save Dominion ratepayers money by avoiding generation investment.

6. Synapse's independent modeling analysis shows that with increased investment in renewables, BESS, and EE, Dominion can reduce the NPVRR of serving data center load by $1 billion over the 15-year planning period and reduce CO_2 emissions by 8 percent over the same time period.

7. Dominion does not have sufficient firm gas pipeline capacity to serve the projected build-out of gas-fired power plants and the full costs associated with building out gas infrastructure are not included in the IRP.

8. Dominion includes $22.4 billion in transmission projects in each of its portfolios—between one-third and two-thirds of which we estimate is entirely avoidable without data center load. Absent action from the Commission to protect ratepayers from data center costs, these costs will be recovered from all ratepayers through Rider T.

Based on those findings, I recommend that the Commission reject Dominion's IRP as submitted and require Dominion to revise its modeling to include the following:

1. Higher annual build limits on solar PV and battery storage in its base scenarios;
2. Long-duration battery storage as a resource option;
3. Incremental investment in EE to at least achieve the annual energy savings targets established in this Court's recent order in Case No. PUR-2023-00227; and
4. An updated load forecast that removes speculative load from the base forecast. Only load with an ESA—that is, those with substantial time and money invested that have achieved tangible milestones to coming online—should be included in a base forecast. All other prospective load should be weighted according to development milestones and included in a high data center load scenario.

Dominion should also be required to submit supplemental analysis on the incremental costs incurred on the gas and transmission systems from data center load, as well as the potential for GETs to lower system costs, to be filed within 90 days of the Commission's final order that includes the following:

5. Supplemental gas analysis should identify the cost of providing a firm gas pipeline capacity to support the projected build out of gas generation it is proposing to build to serve data center load the IRP. Dominion should identify how those costs will be recovered, provide an analysis of fair cost allocation across data center and non-data center customers, and the bill impacts for non-data center customers.
6. Supplemental transmission analysis should provide a breakdown of which planned transmission costs included in the portfolio NPVs are attributed to data centers and which are not. Dominion should identify how those costs will be recovered, provide an analysis of fair cost allocation across data center and non-data center customers, and the bill impacts for non-data center customers.

7. Study on the potential for grid enhancing technologies (GET) to help Dominion address grid challenges from increasing load, while increasing the deployment of renewables to the grid, and the utilization and efficiency of the resources that are already built.

Finally, for its short-term action plan and near-term procurement efforts, Dominion should do the following:

8. Dominion should develop a short-term action plan based on the resources it needs to serve data center load with an ESA—all speculative load should be address in the next IRP.
9. Dominion should begin issuing All-Source RFPs and focus its near-term resource planning efforts on obtaining as much new renewable capacity and energy as soon as possible based on its own modeling results showing that the model will economically deploy as much solar and battery storage as possible starting in the next five years.
10. The Commission should direct Dominion to develop tariffs—similar to large load tariffs being approved or under consideration in Indiana, Georgia, Michigan, West Virginia, and Louisiana—that either (or both) shift the risk of generation investment to companies requesting to add new large loads and commit them to paying their cost of service before assets are built, and enable the build-out of renewable generation to meet load. This will help protect ratepayers from costs associated with prospective load that fails to materialize.

3. DOMINION'S MODELING FRAMEWORK & RESULTS

Q What are the major themes of this IRP relative to Dominion's 2023 IRP?

A As with its 2023 IRP, Dominion's current IRP focuses on the challenges of meeting data center load, which is driving the need for substantial new energy and capacity and is driving the need to keep existing coal and gas resources online. Another major theme is compliance with the VCEA, which mandates that Dominion gradually produce 100 percent of its energy from carbon-free sources over the next twenty years, by 2045. The VCEA also sets development targets for solar PV, wind, battery storage, and EE, and requires the retirement of all carbon-emitting resources by 2045, with exceptions only for threats to grid reliability.

The main update the Company made to the 2024 IRP is to model compliance with current federal carbon regulations for power plants under Section 111 of the Clean Air Act (Section 111 Rules), which were not finalized at the time of the 2023 IRP.[1] The 2024 IRP comes at a time of continued uncertainty regarding carbon regulation in the United States, with the possibility that the Section 111 Rules will be weakened over the next four years. While the details of the rules may change, it is still in effect, and it is very likely that Dominion will face some level of carbon regulation over the next 15 years, whether at the federal or regional level (e.g., through Virginia's renewed participation in RGGI). I therefore find that the scenarios in the 2024 IRP that include the Section 111 Rules serve as a proxy for the future policy landscape that Dominion is likely to face and are the most realistic base scenarios.

1 New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024).

Q Which of Dominion's scenarios do you focus on for your analysis?

A Dominion presents four policy cases in its original filing: REC RPS Only with EPA, REC RPS Only without EPA, VCEA with EPA, and VCEA without EPA.[2]

"EPA" refers to whether Dominion includes the impact of the Section 111 Rules in the scenarios. "VCEA" scenarios include both the renewable portfolio standards (RPS) and renewable procurement targets from the VCEA, while "REC RPS Only" scenarios omit the VCEA procurement targets but continue to model the RPS requirements. In its supplemental filing, the Company also models two additional scenarios that test resource builds in the absence of data center load growth. Finally, Dominion models a number of sensitivities to examine the impact of different levels of load growth, capacity price forecasts, and resource build limits.

My testimony focuses on the VCEA with EPA scenario, as that is the only scenario that complies with all state and federal requirements. I compare Dominion's results with and without data centers to isolate the impact of data center load growth on Virginia's ratepayers, and I use VCEA with EPA portfolio as the baseline for comparison with the Synapse alternative portfolio.

Q How do data centers impact Dominion's load forecast?

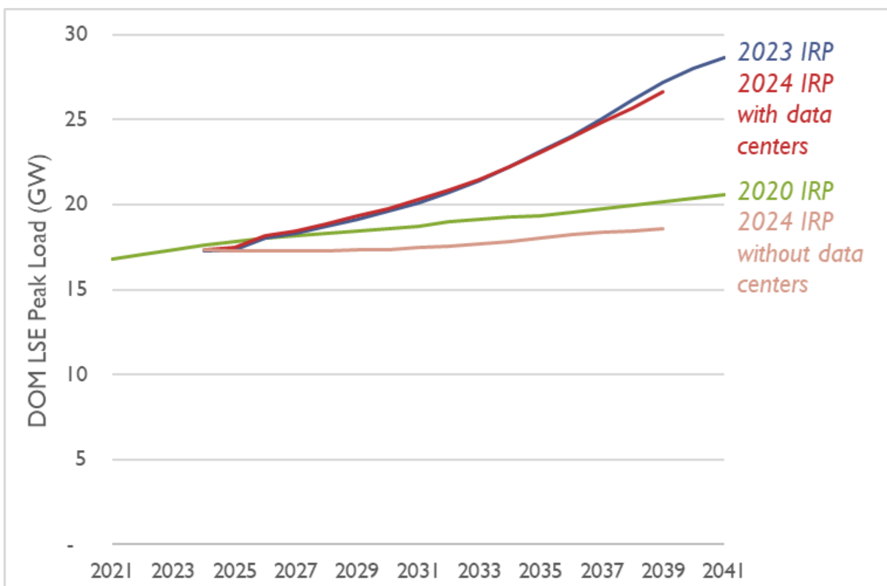
A The Company currently projects that peak load in the Dominion LSE will grow with an average compound annual growth rate of 2.9 percent from 2024–2039, compared to 0.5

2 2024 IRP at 55.

percent in the absence of data centers (Figure 1 below); data centers increase peak load in the LSE by 2.4 GW in 2030 (13.9 percent) and 8.0 GW by 2039 (43 percent).[3] Dominion states that load growth through 2032 is supported by data centers with executed Electric Service Agreements (ESA).[4] Load growth beyond that is speculative.

Dominion's 2024 IRP load forecast with data centers is similar to the one used in its 2023 IRP, while the load forecast without data centers is comparable to its 2020 IRP load forecast (Figure 1). This suggests that data centers are responsible for essentially all of the increase in Dominion's load projection since 2020.

Figure 1. Dominion's Projection of Load Growth in the DOM LSE in the 2020, 2023, and 2024 IRPs



Sources: Dominion 2020 IRP at 40; Dominion 2023 IRP, Attachment Sierra Club Set 02-04 (JLM); 2024 IRP Supplement at 3.

3 2024 IRP Supplement at 3.

4 2024 IRP at 13-14; 2024 IRP Supplement at 1-2.

Q How do Dominion's resource builds differ with and without data center load?

A The data centers are responsible for a large quantity of new resource additions as show in Table 1 below. Relative to the no-data-centers case, the with-data-centers case builds an additional 3.4 GW of new gas capacity (roughly doubling the amount of new gas capacity built), an additional 1.3 GW of SMR capacity, an additional 1.8 GW of storage capacity, and an additional 3.4 GW of offshore wind capacity. In the absence of data center load, Dominion's modeling does not select any SMR capacity.

A notable exception to this pattern of resource additions is solar, which is economic for Dominion to procure regardless of future load growth. The model selects 12.2 GW of new solar in both the scenario with data centers and the scenario without data centers.

Table 1: Resource Builds With and Without Data Centers in Dominion's Modeling (MW)

Resource Type	VCEA with EPA, No Data Centers	VCEA with EPA, with Data Centers	Incremental Build to Serve Data Centers
Solar	12,210	12,210	-
Wind	60	3,460	3,400
Storage	2,250	4,100	1,850
Coal to Gas Conversion	2,754	2,754	-
Gas	2,580	5,934	3,354
Nuclear	-	1,340	1,340

Sources: 2024 IRP Supplement at 5; 2024 IRP Appendix 3A (iv-v).

Q Please summarize the resource retirements Dominion modeled over the next 15 years with and without data center load.

A Dominion modeled no retirements for the next 15 years in any of its scenarios with data center load. As shown in Table 2 below, this is a difference from the Company's modeling in its 2020 IRP where Dominion modeled the retirement of 439 MW of coal capacity at Clover in 2025; 165 MW of gas capacity at Rosemary in 2027; and 153 MW of biomass capacity at the Altavista, Hopewell, and Southampton sites in 2028. Dominion delayed the retirement of these units starting with the 2023 IRP, which was the first to address projected load growth from data centers.

Table 2. Unit Retirements from Dominion's 2020 IRP Alternative Plan B and 2024 IRP

Year	2020 IRP (MW)	2024 IRP (MW) *(all scenarios)*
2025	Clover 1 and 2 (439 MW)	
2026		
2027	Rosemary (165 MW)	
2028	Altavista (51 MW) Hopewell (51 MW) Southampton (51 MW)	

Sources: 2024 IRP at 61; Commonwealth ex rel. State Corporation Commission in re: Virginia Electric & Power Company's Integrated Resource Plan Filing, Case No. PUR-2020-00035, Report of Integrated Resource Plan at 28 (May 1, 2020).

Q When does Dominion plan to retire its existing fossil units?

A Aside from five small oil-fired units that Dominion hard-coded in its modeling to retire in 2026,[5] Dominion does not retire any fossil units during the 15-year study periods in any of its portfolios. Instead, Dominion plans to keep its gas and coal plants online for energy and capacity to meet its growing data center load and maintain reliability while expanding renewable generation. Additionally, the Company plans to keep its three biomass units online to facilitate RPS compliance. This is concerning because the VCEA requires the retirement of all carbon-emitting resources by 2045 (with an exception only for reliability reasons). Also, as I discuss below, the cost of running the fossil units has not improved since the prior IRPs, and these are expensive sources of generation for the Company to continue relying on.

Q What resources does Dominion add to its system in the VCEA with EPA portfolio?

A Focusing on just Dominion's scenarios with data center load now, Table 3 below shows the annual resources additions by resource type in the VCEA with EPA portfolio. Dominion plans to add 6.1 GW of power purchase agreement (PPA) solar, 5.1 GW of utility-owned solar, and 990 MW of distributed energy resource (DER) solar throughout the study period. It also plans to add 3.5 GW of wind (mostly offshore), 4.1 GW of storage, 5.9 GW of new gas capacity, and 1.3 GW of SMR capacity. The model finds utility-scale solar and battery storage particularly economic and builds as much of

5 Company's Response to Commission Staff Discovery Request No. 2-70, attached as Exhibit DG-2.

both resource types as is available every year from 2029 onwards. It also builds wind and gas capacity up to the cumulative limits Dominion put in place and adds the maximum amount of SMR capacity in each year starting in 2035.

Table 3. Capacity Additions in Dominion VCEA with EPA (MW)

Year	Solar PPA	Utility PV	Solar DER	Wind	Storage	Natural Gas Fired	SMR (Nuclear)	Capacity Purchases
2025	-	-	-	-	-	-	-	2,352
2026	-	-	-	-	-	-	-	3,200
2027	-	-	-	-	-	-	-	2,300
2028	-	-	-	-	250	-	-	2,800
2029	591	429	45	-	350	-	-	2,800
2030	591	429	66	-	350	944	-	2,500
2031	552	468	75	60	350	-	-	2,800
2032	552	468	87	-	350	1,268	-	2,200
2033	552	468	96	-	350	818	-	2,400
2034	552	468	99	800	350	818	-	2,700
2035	552	468	102	-	350	818	268	2,500
2036	552	468	102	-	350	1,268	268	2,200
2037	552	468	105	-	350	-	268	2,700
2038	552	468	108	-	350	-	268	3,200
2039	552	468	105	2,600	350	-	268	3,300
Total	**6,150**	**5,070**	**990**	**3,460**	**4,100**	**5,934**	**1,340**	**39,952**

Source: 2024 IRP at 61.

Q **How does Dominion create the portfolio of resources it presents in its VCEA with EPA portfolio?**

A Dominion uses PLEXOS, a model designed for capacity optimization and dispatch. In the VCEA with EPA scenario, Dominion programs into PLEXOS its planned resource additions and VCEA storage and solar procurement targets.[6] The remaining resources

6 Company's Response to Commission Staff Discovery Request No. 9-180, attached as Exhibit DG-3.

are selected endogenously by the model based on least-cost optimization.[7] Because the model is so capacity-constrained, the utility-scale additions that Dominion hard-codes to meet VCEA targets would also have been selected by the model on an economic basis in the scenarios with data center load (as they are in the RPS Only scenarios, which do not include the VCEA procurement targets).

In addition to resource additions, Dominion allows the PLEXOS model to optimize retirement dates for its existing fossil resources. However, the model does not find it economic to retire any of the fossil units because of the large capacity and energy needs of the system.[8] Even in the scenarios without data centers in Dominion LSE the model maintains the Company's legacy fossil fleet. This result is driven by the data center load growth—and associated shortage of capacity and high market prices—in the rest of PJM. In the scenarios that include the Section 111 Rules, Dominion models its three remaining coal plants—Clover, Mount Storm, and the Virginia City Hybrid Energy Center (VCHEC)—as converting to gas by January 1, 2030.[9]

7 Company's Response to Commission Staff Discovery Request No. 8-164, attached as Exhibit DG-4.

8 2024 IRP at 74.

9 Company's Response to Commission Staff Discovery Request No. 3-86, attached as Exhibit DG-5.

Q What impact do the data centers have on the NPVRR of Dominion's portfolios?

A The NPVRR of the VCEA with EPA portfolio with data center load is $102.9 billion, compared to $80.8 billion without data center load.[10] The $22.1 billion increase in NPVRR caused by the data centers represents a 27 percent increase and is primarily the result of the increased resource build-out necessary to serve the load (Table 1).

Q What are the bill impacts of the data center load?

A At the request of Staff, Dominion conducted supplemental modeling and analysis to isolate the impact of data center load growth on its resource plan and customer bills.[11] Dominion finds that, under a no-data-center scenario, residential customers will face higher bills in the near term (2029) and long term (2039), and lower bills in the middle term (2034), relative to the scenarios with data centers. Dominion explains this counterintuitive finding as follows:

> Without additional data center growth, the models result in (i) fewer combustion turbines, PPAs and storage; (ii) lower RPS requirements; and (iii) the elimination of additional offshore wind and SMR resources. Each of these changes reduce and/or delay costs. The loss of offshore wind reduces costs for constructing the resources, however, the customers lose the benefits (capacity, fuel) associated with those facilities. This is especially true in the out years of 2038 and 2039 when the original build plan has those resources fully functioning. Additionally, the analysis shows that assuming no data center

10 2024 IRP Supplement at 5.

11 2024 IRP, SCC Directed 2024 IRP Supplement; Dominion Supplemental Response to Staff Request 8.170, attached as Exhibit DG-6.

> growth, results in residential customers being allocated a greater share of the costs associated with the existing resources.[12]

This finding is driven by several factors. First, data center load in the rest of PJM drives up market prices even in the absence of data center load in the DOM Zone. Second, the PJM energy and capacity market prices that Dominion uses in its modeling are created by ICF based on PJM's full load forecast—which includes Dominion's data center load. Dominion stated that for its supplemental modeling it utilized the same forecasts for energy, renewable energy certifications, and other commodities that served as inputs to the 2024 IRP.[13] As a result, even the scenarios that Dominion models without data center load rely on higher market prices designed with Dominion data center load.

Q What build constraints does Dominion use in its IRP modeling?

A In its modeling, Dominion places an annual build limit on most resources, including 350 MW per year for battery storage, and 1,020 MW per year for solar PV (see Table 4). This build limit constrains the quantity of resources added, as the model maxes out its solar PV additions in every year that utility-scale solar was available (2029–2039) and its battery storage additions in every year from 2029 onwards.[14] Onshore wind also faces a

12 *Id.*

13 2024 IRP Supplement at 4; As part of its supplemental update, Dominion did use an updated capacity price forecast—which reflected even higher prices between now and 2030 –but the updates reflected the most recent PJM capacity market forecast (from July 2024) and were not related to the removal of Dominion data center load.

14 2024 IRP at 61.

low, binding cumulative build limit of only 60 MW throughout the entire study period, which the model adds in the first year it is available.

Table 4. Build Limits in Dominion's PLEXOS Modeling

Asset	Annual Limit	Cumulative Limit	Earliest COD
4-Hour BESS	350 MW	None	2028
Utility-Scale Solar	1,020 MW	None	2029
Distributed Solar	81 MW through 2027 102 MW in 2028–29 120 MW for 2030–39	None	2028
Onshore Wind	1 unit / 60 MW	1 unit	2031
Offshore Wind	1 unit / 800 MW 1 unit / 2,600 MW	1 unit 1 unit	2032 2036
SMR	1 unit / 268 MW	None	2034
2x1 CC	1 unit / 1,268 MW	2 units	2032
2X Advanced CT **4X CT**	1 unit / 818 MW 1 unit / 944 MW	3 units 1 unit	2032 2030
Pumped Storage	1 unit / 300 MW	1 unit	2035

Sources: 2024 IRP at 55, Figure 5.1.1; Company's Response to Sierra Club Discovery Request No. 1-2, Green Sheets (CJR) ES.xlsx.[15] *The COD listed in the table is the first full year that the resource is available, e.g., a resource that comes online in December 2027 is listed with an earliest COD of 2028.*

15 The Company's Response to Sierra Club Discovery Request No. 1-2 includes voluminous spreadsheet data. As such, the input sources are not attached as exhibits to this testimony but can be provided to the Commission and properly-authorized parties upon request.

Q What other findings do you want to highlight from Dominion's modeling?

A In Dominion's core policy scenarios, the model builds up to the programmed build constraints. As a result, resource additions are similar across all scenarios because the model adds the maximum amount of each resource type available regardless of the policy environment. At the direction of the North Carolina Public Utility Commission (NCUC), Dominion models a sensitivity with annual build limits for solar and storage that increase over time. In the sensitivity, Dominion increases the solar annual build limit to 1,500 MW per year starting in 2033 and 2,040 MW per year beginning in 2037.[16] For battery storage, Dominion increases the build limit to 550 MW per year in 2033 and 700 MW per year in 2037.[17]

Even with increased build constraints, the model adds as much solar PV as it is allowed in every year 2029–2039 and adds as much storage as it is allowed in every year 2031-2039 (see Table 5). This underscores the fact that it will be economic for Dominion to add as much solar and storage to its system as it can procure at a reasonable price. Notably, with more storage available to it, the model delays selection of the first SMR until 2038, close to the end of the study period. In addition, the NCUC sensitivity portfolio has a slightly lower NPVRR ($102 billion compared to $102.9 billion for the main VCEA with EPA portfolio). This will save customers around $1 billion compared to the main VCEA with EPA portfolio.

16 2024 IRP at 70.

17 *Id.*

Table 5. Capacity Additions in NCUC Directed Sensitivity

Year	Solar PPA	Utility PV	Solar DER	Wind	Storage	Natural Gas-Fired	SMR (Nuclear)	Capacity Purchase
2025	-	-	-	-	-	-	-	2,352
2026	-	-	-	-	-	-	-	3,200
2027	-	-	-	-	-	-	-	2,300
2028	-	-	-	-	300	-	-	2,800
2029	591	429	45	-	300	-	-	2,800
2030	591	429	66	-	250	944	-	2,500
2031	552	468	75	60	350	-	-	2,900
2032	552	468	87	-	350	1,268	-	2,300
2033	1,032	468	96	-	550	818	-	2,300
2034	1,032	468	99	800	550	818	-	2,600
2035	1,032	468	102	-	550	818	-	2,500
2036	1,032	468	102	-	550	1,268	-	2,300
2037	1,572	468	105	-	700	-		3,000
2038	1,572	468	108	-	700	-	268	3,300
2039	1,572	468	105	2,600	700	-	268	3,300
Total	**11,130**	**5,070**	**990**	**3,460**	**5,850**	**5,934**	**536**	**40,452**

Source: 2024 IRP at 70

Q Do you have any concerns with Dominion's assumptions emerging technology availability?

A Yes. Specifically, Dominion's representation of emerging technologies may not accurately reflect the availability of resources it will see going forward. Dominion's deployment plans for SMRs are ambitious. SMRs are not commercially deployed and may not be available on a 2035 timeline or at the cost that Dominion currently projects. This is especially true given that the SMR industry has yet to deploy the first of its kind in a utility application.[18] In November 2023, Utah Associated Municipal Power System

18 2024 IRP at 16.

terminated its SMR project with NuScale Power after the project cost rose from its original estimate (in 2015) of $3 billion for a 600 MW plant ($5,000/kW) to a final estimate in 2023 of $9.3 billion for a scaled-down 462 MW plant ($20,130/kW).[19] Dominion modeled SMRs with a cost of $11,147/kW ($2024).[20] That cost is both high for a generation resource, and low relative to the limited market data available on SMR project costs. Given the nascence of the SMR industry and the documented cost overruns incurred at traditional nuclear projects at Plant Vogtle in Georgia[21] and VC Summer in South Carolina,[22] Dominion should be planning around technologies with lower risks and uncertainty.

Q What emerging technologies should Dominion be modeling?

A Dominion should be modeling LDES, as it is less risky and likely to be available before SMRs. Dominion itself has two active LDES pilots: a 100-hour iron-air battery at the Darbytown Power Station and a 10-hour nickel-hydrogen battery at Virginia State University.[23] At least six pilot projects are active in the US including in Georgia,[24] New

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19 M.V. Ramana, *The Collapse of NuScale's Project Should Spell the End for Small Modular Nuclear Reactors*, UTILITY DIVE (January 31, 2024), available at https://bit.ly/3XorEdt.

20 2024 IRP, Appendix 3K-3.

21 U.S. ENERGY INFORMATION ADMINISTRATION, *Plant Vogtle Unit 4 Begins Commercial Operation* (May 1, 2024) available at https://bit.ly/3EYazRj.

22 Jessica Holdman, *Seven Years After South Carolina Nuclear Debacle, Advisory Group Suggests Potential Restart of Failed Project*, SOUTH CAROLINA DAILY GAZETTE (October 15, 2024), available at https://bit.ly/4bpM8Z9.

23 2024 IRP at 41–42.

York,[25] Colorado, and Minnesota (where there are actually two pilot projects).[26] Given that at least six utilities and resource authorities—including Dominion itself—have found LDES technology to be advanced and commercially developed enough to deploy pilots as part of their grid, the Company should be modeling it as a new resource option. Including LDES in the model can help reduce Dominion's reliance on SMRs, protecting ratepayers from the risk of cost overruns associated with SMR buildout.

LDES can also reduce Dominion's need to add new gas resources, which have a high risk of becoming stranded assets under the VCEA requirement that Dominion retire all emitting generation assets by 2045.

Q **Do you have concerns with Dominion's modeling of energy efficiency?**

A Yes, Dominion's modeling does not include EE sufficient to meet the current statutory requirement of 5 percent reduction in energy consumption in 2025 relative to 2019

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24 Jason Plautz, *Form Energy Announces Partnership with Georgia Power to Test 100-Hour Iron-Air Battery*, UTILITY DIVE (February 10, 2022), available at https://bit.ly/4ig8778.

25 NEW YORK STATE ENERGY RESEARCH & DEVELOPMENT AUTHORITY, *Nearly $15 Million Awarded to Four Demonstration Projects to Advance Long Energy Duration Energy Storage Technology Solutions* (August 17, 2023), available at https://bit.ly/4im5DnT.

26 Andy Colthrope, *U.S. Utility Xcel to Put Form Energy's 100-Hour Iron-Air Battery at Retiring Coal Power Plant Sites*, ENERGY STORAGE NEWS (January 27, 2023), available at https://bit.ly/41zalcf; Kristi Marohn, *Xcel Energy to Add Iron-Air Battery System to Store Electricity in Becker*, MPR NEWS (January 26, 2023), available at https://bit.ly/3D6THr7; Frank Jossi, *Minnesota Utility Co-op Sees Big Battery as Piece of Grid Reliability Puzzle*, ENERGY NEWS NETWORK (September 10, 2021), available at https://bit.ly/4h38Wiw.

levels.[27] Dominion's modeling is also insufficient to meet the Commission-ordered targets of 3 percent in 2026, 4 percent in 2027, and 5 percent in 2028, recently established in Case No. PUR-2023-00227.[28] Instead, Dominion modeled baseline EE assumptions consistent with what it proposed—and what the Commission rejected—in that case: 2.09 percent, 2.39 percent, and 2.72 percent in 2026, 2027, and 2028, respectively.[29]

Q Did Dominion evaluate alternative technology options, such as GETs to lower grid costs for ratepayers?

A No. Dominion is also not robustly considering GET or non-wires alternatives (NWA) as part of any portfolio.[30] During the IRP Stakeholder process, GETs emerged as an issue of interest and concern to Dominion's stakeholders. The Company included a short discussion in Appendix 2D in the section in "Future Technology Considerations" and indicated that it only provided GETs in its IRP in response to stakeholder feedback.[31]

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27 Virginia Code § 56-596.2 B 2.

28 *Commonwealth ex rel. State Corporation Commission in re: Establishing Energy Efficiency Savings Targets for Virginia Electric & Power Company*, Case No. PUR-2023-00227, Final Order (February 27, 2025), available at https://bit.ly/3XhGBOI (Dominion EE Targets Final Order)

29 2024 IRP, Appendix 3D at 1. Percent is described as a cumulative EE Savings relative to 2019 sales.

30 2024 IRP at 24.

31 2024 IRP at 24.

GETs are not intended to displace the need for new generation to serve large and concentrated data center load, but rather to ensure that ratepayers are getting the most of out the existing technology and infrastructure on the grid. While data center load growth is front and center in the current IRP, the electric grid is still facing issues around electric vehicle load (EV), home electrification, renewable curtailment, and transmission congestion. GETs can help Dominion address these and other challenges, increase the deployment of renewables to the grid, and increase the utilization and efficiency of the resources that are already built. And all at a lower cost than relying on new generation solutions or even existing network upgrade solutions.

Q What are GETs?

A GETs encompass a range of hardware and software grid technologies that can improve operational flexibility and improve grid performance. Software solutions can enhance control, protection, metering and response while hardware solutions can improve physical assets and infrastructure that transmits electricity. Some examples include:

- *Dynamic Line Ratings* (DLR), Dynamic Transformer Ratings which utilize sensors to calculate line and transformer ratings based on real-time weather conditions rather than using the conservative static rating.
- *Flexible AC Transmission Systems* (FACTS) are devices that control voltage levels that help dynamically support system voltage across operating conditions, reduce loses and help with system voltage recovery following a loss event.
- *Fixed Series Capacitor Banks* (FSCs) are devices that compensate for the impedance of overhead lines and reduce voltage drops at points of connection.
- *Advanced Power Flow Controllers* (APFC) are modular devices that can be quickly deployed to allow grid operators to divert electricity flows to avoid congested areas.

- *Topology Optimization* (TO) is a software technology that allows grid operators to re-rout power flows around congested areas.

A number of studies have evaluated and quantified the potential benefits from various GETs.[32]

- A study from CIGRE evaluated DLRs and found that the technology could increase transmission capacity 33 percent in the winter and 19 percent in the summer. The payback period for the technology was extremely short—less than six months—and the savings were between $2 billion and $8 billion annually.[33]

- A study for RMI evaluated GET projects across five states in the PJM region—Illinois, Indiana, Ohio, Pennsylvania, and Virginia—and found that they could help connect 6.6 GW of new solar PV, wind, and storage by 2027. Further, GET solutions were found to be substantially less expensive than traditional network upgrades required for interconnection.[34]

Q What do you recommend with regards to GETs?

A As the load-serving utility, Dominion is best placed to conduct a detailed study outlining the potential of GETs to optimize its existing system and avoid costly investments and upgrades. I recommend that Dominion conduct a supplemental analysis of the potential for GETs to lower system costs and avoid costly investments in transmission upgrades as soon as possible, and no later than its next IRP.

32 Yaron Miller & Maureen Quinlan, *To Ease Energy Transmission Gridlock, States Look to Grid-Enhancing Technologies*, PEW (May 8, 2024), available at https://bit.ly/41y4Iei.

33 K. Engel *et al.*, *An Empirical Analysis of the Operational Efficiency and Risks Associated with Static, Ambient Adjusted, and Dynamic Line Rating Methodologies*, CIGRE-US NATIONAL COMMITTEE (July 2021), available at https://bit.ly/4igsUY5.

34 Katie Mulvaney *et al.*, *GETing Interconnected in PJM*, ROCKY MOUNTAIN INSTITUTE (February 2024), available at https://bit.ly/4hRE5qu.

4. SYNAPSE'S ALTERNATIVE SCENARIO

Q Please describe the modeling exercise that Synapse completed relating to Dominion's 2024 IRP.

A Synapse completed independent modeling that replicated Dominion's with- and without-data center scenarios, as well as alternative scenarios that illustrate potential methods for Dominion to reduce the costs, emissions, and risks to its ratepayers from serving load from data centers.

Q Please summarize the modeling tool and capabilities of the tools Synapse relied on.

A For the Synapse analysis I use the EnCompass capacity optimization and dispatch model to simulate resource choice and impacts in Dominion's service territory. The model was developed by Anchor Power Solutions (now Yes Energy) and covers all facets of power system planning, including:

- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load shaping and shifting capabilities;
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis;
- Long-term integrated resource planning, including capital project optimization, economic generating unit requirements, and environmental compliance; and
- Market price forecasting for energy, ancillary services, capacity, and environmental programs.

Q Is the EnCompass model used throughout the power sector?

A Yes. The model was released in 2016 and is currently used by a number of major investor-owned utilities. These include Minnesota Power, Otter Tail Power, Excel

Energy (in Minnesota, New Mexico, Colorado, and Texas), Great River Energy, Duke Energy (in the Carolinas and Indiana), and Public Service Company of New Mexico.

Q Describe the scenarios that Synapse models.

A Synapse models three scenarios focused on isolating the impact of data center load. We model reference scenarios that are VCEA and EPA compliant with and without data center load, and an alternative scenario (also VCEA and EPA compliant) that evaluates additional renewables and efficiency investment with data center load. All scenarios include coal-to-gas conversions for the three coal plants in Dominion's portfolio to comply with the Section 111 rule.

- **Reference VCEA and EPA compliant with data center load**. Synapse ran this scenario to compare the resulting revenue requirement of the Company's preferred resource portfolio to Synapse's alternative portfolios.
- **Reference VCEA and EPA compliant without data center load.** This scenario provides an independent assessment of the impact of data centers on Dominion's resource builds and revenue requirement.
- **Synapse alternative with data center load.** Synapse ran this scenario to evaluate the benefits to ratepayers of Dominion meeting its energy efficiency targets, procuring renewables more rapidly than Dominion assumes in its modeling, and procuring long-duration energy storage as part of its resource portfolio.

Q How do Synapse's input assumptions and model parameters compare to the ones Dominion uses?

A To ensure our results are comparable to Dominion's, we maintain as many of Dominion's assumptions as possible in our scenarios.[35] Specifically, we use Dominion's assumptions for peak and annual energy, load shape, reserve margin, the first two offshore wind unit project additions, distributed solar additions, fuel commodity prices, resource capacity values, resource maximum capacity factors, resource capital costs, and import limits. Table 6 shows the sources we rely on for our modeling.

Table 6. Synapse EnCompass Modeling Input Sources

Item	Source
Load Forecast	Attachment United Set 2-09 (a) (JLM) SUPP
Reserve Margin	Response to Staff 1-48, Attachment Appendix 5C VCEA with EPA (AWD) CONF
Coal Prices	Response to Sierra Club 2-1, Attachment VCEA with EPA Plexos Outputs (JLM) CONF
Gas Prices	Response to Sierra Club 2-1, Attachment VCEA with EPA Plexos Outputs (JLM) CONF
RGGI Prices	Synapse modeling (N/A)
Onshore Wind Costs	Response to Sierra Club 2-1, Attachment Capital Costs (JLM) CONF
Offshore Wind Costs	Response to Sierra Club 2-1, Attachment Capital Costs (JLM) CONF
Solar Costs	Response to Sierra Club 2-1, Attachment Capital Costs (JLM) CONF

35 Synapse did not independently evaluate each of the assumptions it incorporated from Dominion's modeling. Rather, we opted to focus on and modify only a few of the Company's assumptions, so as to isolate their impacts and ensure our results were comparable.

Battery Costs	Response to Sierra Club 2-1, Attachment Capital Costs (JLM) CONF
100-Hour Battery Costs	FORM ENERGY, *Clean, Reliable, Affordable: The Value of Multi-day Storage in New England* (September 2023), available at https://bit.ly/41zbpgf.
New Gas CT Cost	Response to Sierra Club 2-1, Attachment Capital Costs (JLM) CONF
SMR Cost	Response to Sierra Club 2-1, Attachment Capital Costs (JLM) CONF
Heat Rates	Response to Sierra Club 2-1, Attachment Operational Data – Existing Resources (JLM) ES
Firm Capacity Ratings	Response to Sierra Club 2-1, Attachment Operational Data – Existing Resources (JLM) ES
Existing Resource Nameplate Capacities	Horizons National Database
Existing Resource FOM & VOM Costs	Horizons National Database
Resource Build Limits	Response to Sierra Club 2-1, Attachment Green Sheets (CJR) ES
RPS Requirement	Response to Staff 1-48, Attachment Pages 58, 60, 62, 64 Portfolio Dashboards Meeting RPS Requirements and Appendix 5C (AWD) CONF.xlsx
Starting RPS Bank	Response to Staff 1-48, Attachment Pages 58, 60, 62, 64 Portfolio Dashboards Meeting RPS Requirements and Appendix 5C (AWD) CONF.xlsx
ELCC Values	Response to Sierra Club 2-1, Attachment Operational Data – Existing Resources (JLM) ES
Renewable Capacity Factors	Response to Sierra Club 2-1, Hourly Wind & Solar Shape (JLM) CONF
Financial Parameters (WACC)	Response to Sierra Club 2-1, Attachment New Resource Parameters (JLM) CONF
Interconnection & Integration Costs	Dominion 2024 IRP, Appendix 2E at 2

Note: Many of these input sources include voluminous spreadsheet data. As such, the input sources are not attached as exhibits to this testimony but can be provided to the Commission and properly-authorized parties upon request.

Q Which of Dominion's inputs or assumptions did your analysis focus on?

A I am concerned that Dominion is unnecessarily restricting renewable deployment in the region and over-estimating future renewable costs. Dominion provided no tangible analysis to justify its renewable build limits stating only that the build limits "account for a realistic build scenario taking into consideration supply chain constraints, construction capacity, interconnection viability, and availability of projects."[36] Therefore, I relaxed the build limits for solar, onshore wind, and BESS in the Synapse alternative portfolio (as discussed below) to evaluate the potential cost savings if the market is able to deliver solar beyond the levels Dominion modeled. I maintained SMRs and also added LDES, which is more likely to be available than SMRs (based on Dominion's current LDES battery storage pilots) and could help reduce investments in non-VCEA compliant gas resources and/or SMRs. Finally, I added EE sufficient to reflect the Commission-ordered targets in Case No. PUR-2023-00227.[37]

Q Explain how you modeled EE in the Synapse alternative scenario.

A I modeled EE sufficient for Dominion to reach the targets recently established by the Commission at 3 percent in 2026, 4 percent in 2027, and 5 percent in 2028. For the Dominion reference scenario, I included Dominion's proposed targets from Case PUR-2023-00227 and designed an updated load forecast with EE incremental to what

36 Company's Response to Commission Staff Discovery Request No. 1-41, attached as Exhibit DG-7.

37 *See* Dominion EE Targets Final Order, *supra* note 28.

Dominion already modeled and necessary to meet the Hearing Examiner's recommended targets. I similarly calculated EE program costs that are incremental to program costs already included in Dominion's load.

Q Why did you increase the renewable build limits?

A PLEXOS build limits are intended to represent actual limits present in the real world, not to constrain real-world consideration of resource additions. Regulatory and interconnection bottlenecks that have slowed renewable deployment over the past several years are easing (as discussed directly below). And while supply chain challenges are still present, federal policies that support domestic manufacturing coupled with solar deployment incentives (investment tax credit and production tax credit) and domestic content adder credits have spurred investment in the US solar and storage manufacturing industries.[38] According to the Solar Energy Industries Association, 73 new solar and storage manufacturing facilities came online since federal manufacturing policies were announced in 2022, with another 48 under construction.[39]

Given the large quantity of new resources that Dominion will need, the Company should be sending signals to the market that it is interested in as much solar, and BESS as it can cost effectively get. While build limits can be useful in representing real-world limitations, they also can place unnecessary constraints on model outputs. By modeling

38 Solar Energy Industries Association, *Solar & Storage Supply Chain Dashboard*, (February 2025), available at https://bit.ly/41B0pyY.

39 *Id.*

a scenario with relaxed constraints, we are evaluating the potential savings available if the market is less constrained than Dominion assumes it will be.

Q Explain the recent generation interconnection reforms referenced above.

A On July 27, 2023, the Federal Energy Regulatory Commission (FERC) issued an order on Improvements to Generators Interconnection Procedures and Agreements. This order adopts reforms to (1) implement a first-ready, first-served cluster study process; (2) speed up interconnection queue processing; (3) incorporate technological advancements into the interconnection process; and (4) establish an effective date and a transition process.[40] These reforms are intended to alleviate the interconnection backlog in PJM and speed up project approval timelines.

In the first cycle of the reformed interconnection process, PJM completed Phase 1 System Impact Studies for 306 proposed projects; these are expected to be ready for construction by mid-2025. Separately, another 306 projects qualified for an Expedited Process; these projects were expected to have final agreements issued throughout 2024. Cycle two under the reformed process had an application deadline in December of last year (2024). In total, PJM expects to process 72,000 MW of projects by mid-2025 and

40 Federal Energy Regulatory Commission, *Fact Sheet: Improvements to Generators Interconnection Procedures & Agreements* (July 27, 2023), available at https://tinyurl.com/nhjhhjpc.

an additional 230,000 over the next three years; 90 percent of those projects are renewables or storage.[41]

Q How do the resource additions compare between Reference VCEA and EPA compliant portfolio and the Synapse alternative portfolio?

A In the Synapse alternative portfolio, the model adds more solar, onshore wind, and battery storage (both 4-hour BESS and LDES) than in the Reference VCEA and EPA compliant portfolio. Also, in the Synapse alternative portfolio the model does not select any new SMR capacity (despite it being allowed to do so if economically competitive). This results in a smaller amount of active nuclear capacity in 2039 compared to the Reference VCEA and EPA compliant with data center load portfolios. Table 7 below shows total installed capacity in 2039.

41 PJM Inside Lines, *PJM Advances to the Next Phase of New Interconnection Process* (May 20, 2024), available at https://bit.ly/4ihWrRs.

Table 7. Comparison of Total Capacity in the Synapse Modeled Portfolios, 2039 (GW)

Resource Type	Reference VCEA & EPA Compliant with Data Centers	Synapse Alternative with Data Centers
Utility Solar	16.9	25.7
DG Solar	0.0	0.0
Offshore Wind	6.0	6.0
Onshore Wind	0.1	1.4
Battery Storage	4.7	10.9
4-Hour BESS	*4.7*	*9.5*
100-Hour Batteries (LDES)	*0.0*	*1.4*
Nuclear	4.9	3.5
Coal	2.7	2.7
Gas	15.3	15.3
Biomass / Landfill / Other	0.0	0.0
Pumped Hydro	1.8	1.8
Hydro	0.3	0.3
Total	**52.6**	**67.5**

Q How do annual resource additions differ between the Reference VCEA and EPA compliant portfolio (with and without data centers) and the Synapse alternative portfolio with data centers?

A Table 8, Table 9, and Table 10 show the annual resource buildouts for the three portfolios. In the Synapse alternative portfolio, the model builds additional solar, onshore wind, and battery storage compared to the Reference portfolio with data center load, as a result of the relaxed build limits for these resources.

In the Synapse alternative portfolio, the model adds 20.1 GW of utility-scale solar over the study period, compared to 11.3 in the Reference portfolio with data centers, and 7.9 GW in the Reference portfolio without data centers.[42] Similarly, in the Synapse alternative portfolio, the model adds 10.4 GW of BESS, including 9.1 GW of 4-hour BESS and 1.4 GW of LDES, compared to 4.2 GW of 4-hour BESS in the Reference with data center portfolio and 2.5 GW in the without data center portfolio. All three scenarios retire one of the Gravel Neck GT units in 2038. In the Reference portfolio without data centers, VCHEC also retires in 2038.

The Reference portfolio without data centers has surplus capacity from 2026 onwards. Both portfolios with data centers (Reference and Synapse alternative) are short on capacity in the near term, necessitating capacity market purchases. In the longer term, the Reference portfolio capacity purchase needs decrease, and there is surplus capacity in some years. The Synapse alternative portfolio has surplus capacity in all years past 2032. In years with surplus capacity, energy needs are driving resource additions.[43]

42 Note that in Dominion's modeling runs, solar additions are the same with and without data center load. In Synapse's modeling runs, the model selected additional offshore wind resources rather than maxing out solar additions in the portfolios without data center load.

43 Synapse capacity purchase quantities vary from Dominion's results in the Reference portfolios. This is due to (1) small differences in nameplate capacities for existing resources between Horizon's National Database and Dominion's values, (2) a different method for determining the reserve margin requirement in the Reference portfolio without Data Centers and (3) Synapse modeling assumes that Dominion only ever purchases capacity up to its exact reserve requirement, whereas Dominion procures surplus capacity above its reserve requirement needs in several years.

Table 8. Annual Capacity Additions (MW) by Resource Type, Dominion VCEA & EPA Compliant (without Data Centers)

Year	Solar	Onshore Wind	Offshore Wind	4-Hour Battery	100-Hour Battery	Natural Gas	SMR	Net Capacity Purchase	Retirements
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	(724)	-
2027	-	-	-	-	-	-	-	(550)	-
2028	-	-	-	350	-	-	-	(711)	-
2029	660	-	-	350	-	-	-	(816)	-
2030	660	-	-	350	-	944	-	(1,480)	-
2031	720	60	-	350	-	-	-	(1,550)	-
2032	720	-	800	-	-	-	-	(1,698)	-
2033	720	-	-	350	-	-	-	(1,301)	-
2034	720	-	-	350	-	818	-	(1,340)	-
2035	822	-	-	-	-	1,268	-	(2,224)	-
2036	960	-	-	-	-	-	-	(2,025)	-
2037	720	-	-	-	-	-	-	(1,932)	-
2038	480	-	-	-	-	-	-	(1,324)	702
2039	720	-	-	350	-	-	-	(1,140)	-
Total	**7,902**	**60**	**800**	**2,450**	**-**	**3,030**	**-**	**(18,814)**	**702**

Table 9. Annual Capacity Additions (MW) by Resource Type, Dominion VCEA & EPA Compliant with Data Centers

Year	Solar	Onshore Wind	Offshore Wind	4-Hour Battery	100-Hour Battery	Natural Gas	SMR	Net Capacity Purchase	Retirements
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	1,001	-
2027	-	-	-	-	-	-	-	1,720	-
2028	-	-	-	350	-	-	-	2,246	-
2029	1,020	-	-	350	-	-	-	2,218	-
2030	1,020	-	-	350	-	944	-	1,712	-
2031	1,020	60	-	350	-	-	-	1,814	-
2032	1,020	-	800	350	-	2,086	-	152	-
2033	1,020	-	-	350	-	2,086	-	(743)	-
2034	1,020	-	-	350	-	818	-	(259)	-
2035	1,122	-	-	350	-	-	274	26	-
2036	1,020	-	2,600	350	-	-	274	(113)	-
2037	1,020	-	-	350	-	-	274	316	-
2038	1,020	-	-	350	-	-	274	490	92
2039	1,020	-	-	350	-	-	274	885	-
Total	**11,322**	**60**	**3,400**	**4,200**	**-**	**5,934**	**1,370**	**11,465**	**92**

Table 10. Annual Capacity Additions (MW) by Resource Type, Synapse Alternative, with Data Centers

Year	Solar	Onshore Wind	Offshore Wind	4-Hour Battery	100-Hour Battery	Natural Gas	SMR	Net Capacity Purchase	Retirements
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	935	-
2027	-	-	-	-	-	-	-	1,656	-
2028	-	60	-	700	-	-	-	1,815	-
2029	-	120	-	750	-	-	-	1,645	-
2030	1,800	120	-	850	-	944	-	776	-
2031	540	120	-	950	-	-	-	722	-
2032	-	120	800	1,000	-	2,086	-	(1,274)	-
2033	-	120	-	50	-	2,086	-	(2,009)	-
2034	2,220	120	-	200	-	818	-	(1,553)	-
2035	3,582	120	-	1,350	270	-	-	(1,838)	-
2036	3,600	120	2,600	650	270	-	-	(2,285)	-
2037	3,240	120	-	550	270	-	-	(2,108)	-
2038	-	120	-	-	270	-	-	(1,489)	92
2039	5,160	120	-	2,000	270	-	-	(1,589)	-
Total	**20,142**	**1,380**	**3,400**	**9,050**	**1,350**	**5,934**	**-**	**(6,594)**	**92**

Q How do generation levels by resource type differ between the Reference VCEA and EPA portfolios and the Synapse alternative portfolio?

A Figure 2 and Figure 3 below show the generation results of the Reference with data center and the Synapse alternative portfolio. Although the Reference and Synapse alternative portfolio have the same quantity of coal and gas capacity, the amount of generation from fossil resources is lower in the Synapse alternative portfolio, especially from 2034 onwards, when the buildout of solar and battery storage in the Synapse alternative portfolio is larger than in Reference modeling. The Synapse alternative portfolio also includes more onshore wind generation and less nuclear generation than the Reference portfolios. In the Reference modeling, by 2039, 31 percent of generation is produced by gas with 40 percent coming from solar and wind. Meanwhile in the

Synapse modeling, by 2039, 23 percent of generation comes from gas, with 58 percent of generation coming from solar and wind.

Figure 2. Reference VCEA and EPA Compliant Portfolio With Data Centers Generation by Resource Type

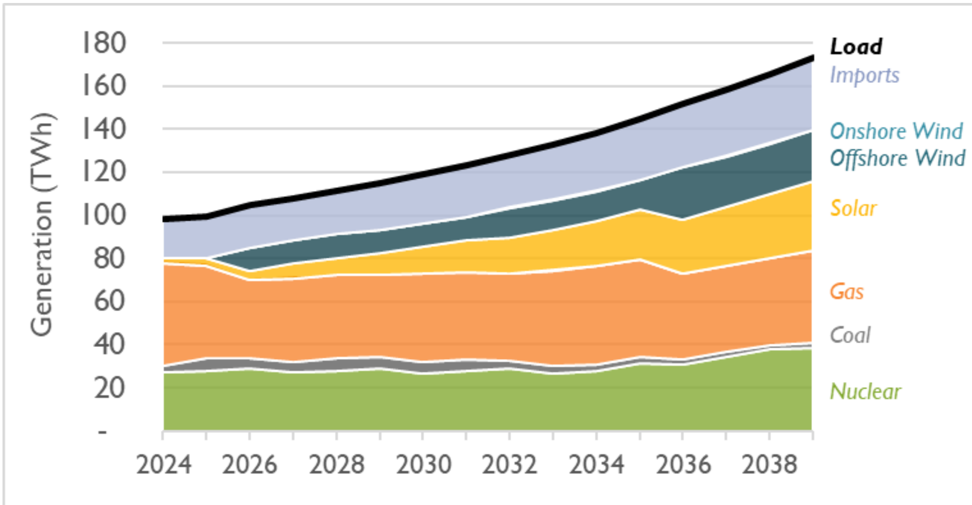
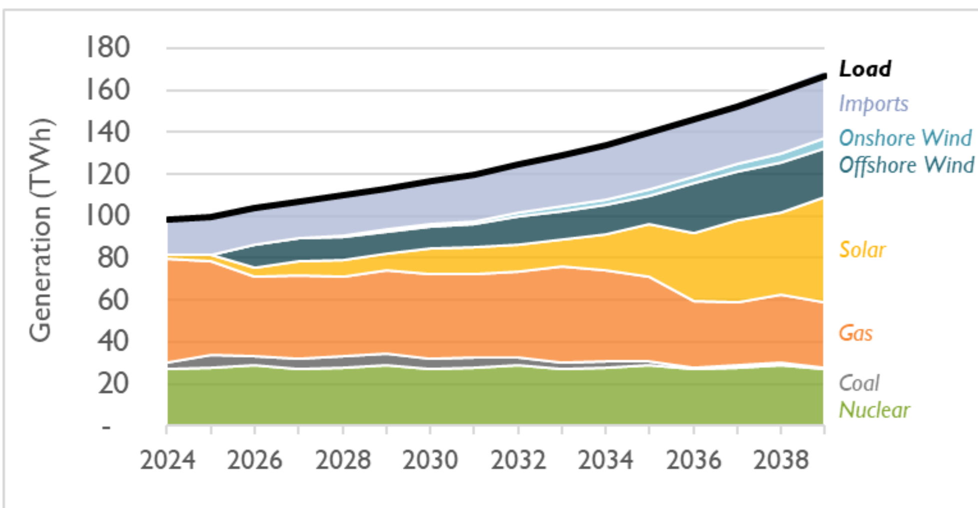


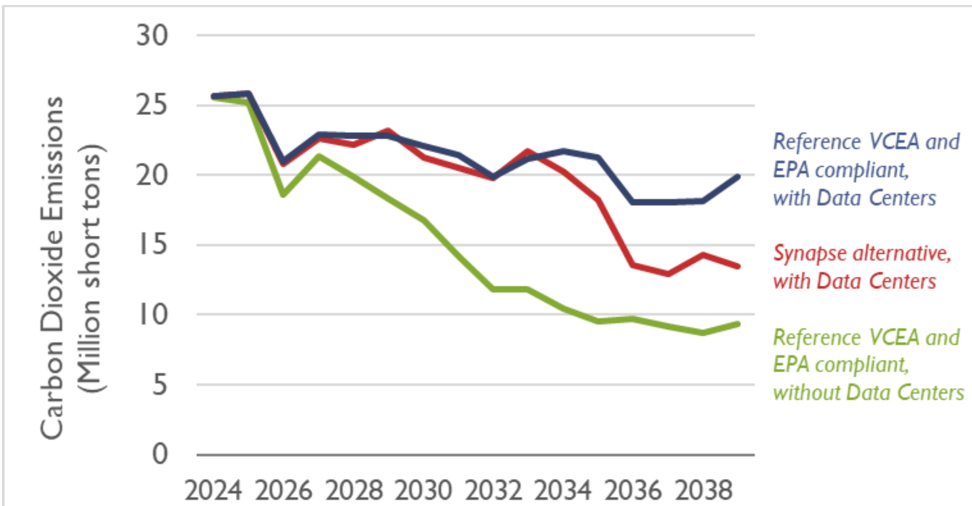
Figure 3. Synapse Alternative Portfolio Generation by Resource Type



Q How do carbon dioxide emissions compare between Reference VCEA and EPA compliant and Synapse alternative portfolio?

A Carbon dioxide (CO_2) emissions decline more in the Synapse portfolio compared to the Reference portfolio (Figure 4). By 2039, annual CO_2 emissions are 48 percent lower than 2024 levels in the Synapse portfolio, compared to a decrease of only 22 percent in the equivalent scenarios in Reference modeling. Total CO_2 emissions over the study period (2024–2039) are 8 percent lower in the Synapse portfolio compared to the Dominion with data centers portfolio.

Figure 4. Carbon Dioxide Emissions in Scenarios Modeled by Synapse



Q How did the revenue requirement and total system costs compare between Reference VCEA and EPA compliant and Synapse alternative portfolios?

A The total cost to ratepayers is $1.1 billion less in the Synapse portfolio as compared to the Reference with data centers portfolio. Table 11 summarizes the NPVRR results of the three scenarios that Synapse modeled. This table does not include the transmission line item from Dominion's NPVRR calculation, because Dominion used a static value across all scenarios, while in reality transmission costs will vary based on the level of load growth and the resource mix, which Dominion did not evaluate, as I discuss in more detail below. The NPVRR of the Synapse portfolio includes the incremental cost of the additional energy efficiency investments.

Table 11. NPVRR (Billion $2024) of Synapse Modeled Scenarios (2025–2039)

Cost Category	Reference VCEA & EPA Compliant (without Data Center)	Reference VCEA & EPA Compliant with Data Center	Synapse Alternative with Data Center
Operating Cost	$48.50	$62.73	$60.71
Property Taxes	$0.26	$0.84	$0.67
Other Costs	$0.02	$0.05	$0.05
Book Depreciation	$1.84	$4.55	$4.77
Allowed Return	$1.20	$5.89	$5.64
RPS Penalties	$0.00	$0.00	$0.00
Integration	$0.86	$1.11	$1.62
REC Purchases	-$1.03	-$0.36	-$2.53
Incremental EE Costs	$0.00	$0.00	$2.74
Total Cost	$51.66	$74.79	$73.66

Note: Other costs include insurance, program costs, RGGI

Q What should the Commission take away from the Synapse modeling?

A Starting in 2028, the model selects as much renewable and battery storage as it can in the Reference with data center portfolio, and the model finds it economic to select significantly more renewable capacity when build limits are relaxed in the Synapse alternative portfolio.

Importantly, a portfolio with more clean energy is lower-cost than the Company's current plan to build out significant SMR capacity. Increased solar, battery, and onshore wind capacity paired with LDES deployment completely avoid investment in SMRs in the Synapse alternative portfolio. Assuming clean energy costs continue to fall, and interconnection queues are cleared, the savings to Dominion ratepayers from investing in renewables will grow even larger. Additionally, investment in EE levels that at least meet statutory requirements deliver savings to ratepayers by avoiding unnecessary investment in incremental generation.

Q What are your key findings and recommendations from the Synapse modeling?

A Dominion should issue RFPs and begin to procure solar PV, battery storage, and onshore wind to meet the growing data center load. Proactive procurement of clean energy resources will result in lower costs and risks for ratepayers and will help Dominion avoid the need to invest in more costly and speculative options such as SMRs.

5. ECONOMIC & REGULATORY FACTORS IMPACTING THE IRP

A. Data Center Load Growth & Resource Planning

Q Explain the data center load growth that is driving the need for Dominion to build out a significant quantity of new resources.

A As discussed in section 3 above, Dominion is once again projecting enormous data center load growth in the region over the next decade in its 2024 IRP. The region hosts the largest data center market in the world.[44] Specifically, the PJM Load Forecast projects Dominion's peak demand will grow by nearly 5.5 percent annually and double

44 Dominion 2024 IRP at 13.

by 2039, compared to recent observed peaks.[45] The 2024 PJM forecast projects a 15-year CAGR for coincident peak demand and energy of 4.8 percent and 6.8 percent respectively.[46] This is a substantial difference from the level of load growth that Dominion projected in its 2020 IRP before the Company began planning for data center growth.

Dominion is not the only jurisdiction in the country facing high data center load growth—this is a trend occurring around the country, with the main hubs being in Texas, PJM, and Georgia.[47] Utilities and Commissions across the country are taking actions to protect ratepayers from the impacts of the data center load (as I will discuss below). But I see no such plan here. Furthermore, it is concerning that Dominion is planning to build for such a high level of data center load growth without a clear plan for how to protect residential and other non-data center customers.

Q What risks are posed for non-data center customers, given Dominion's modeled resource additions?

A Data center load poses a number of risks to non-data center ratepayers—both in scenarios where the load actually materializes, as well as in scenarios where it doesn't.

45 Dominion 2024 IRP at 1.

46 *Id.* at 8–9.

47 Electric Power Research Institute, *Powering Intelligence: Analyzing Artificial Intelligence & Data Center Energy Consumption* (May 28, 2024), available at https://bit.ly/41EIPZV; John D. Winson *et al.*, *Strategic Industries Surging: Driving U.S. Power Demand*, Grid Strategies (December 2024), available at https://bit.ly/4iBHw4P.

First, there is the risk of Dominion building out large amounts of resources for prospective customer load that may not materialize fully or at all. If Dominion builds new generation resources for load that does not materialize, all ratepayers will be left paying for unneeded assets.

Second, even if the data center load does materialize, large generation and transmission build-out can increase system costs for all ratepayers under current tariff structures. There is the risk of Dominion shifting costs to other ratepayers from building out a large quantity of new generation resources. Large generation build-out can increase system costs for all ratepayers under current tariff structures. This can result from increases in energy and capacity market prices, additional transmission and gas infrastructure investments, and general cost shifting if rates and tariffs are not set up correctly to have data center customers cover their full incremental cost of service.

Q What is the basis of Dominion's data center load forecast?

A Dominion states that it uses both historical metered data and forward-looking customer intelligence to create its load forecast.[48] For many prospective data center customers, Dominion has detailed information on what construction, interconnection, and development milestones the customer have met. The customer can be broadly grouped into three categories based on milestones. Prospective customers in all three stages are included in the load forecast, with near-term load including only those with signed

48 2024 IRP at 14.

energy service agreement (ESA) and load further out including prospective customers in the construction letter of authorization (CLOA) category. The customer milestones, listed in order from most to least committed, are as follows:

- Energy Service Agreements (ESAs) for 8,172 MW of new data center load by 2032. This approximately matches Dominion's metered load forecast through 2032, meaning all of this load is included in Dominion's load forecast. ESAs commit a customer to take a certain level of electricity annually.[49]
- Construction Letters of Authorization (CLOAs) for 5,835 MW of customer load. CLOA's enable construction of distribution and substation infrastructure by the Company, the cost of which the Customer must reimburse Dominion for if they discontinue the project.[50]
- Substation Engineering Letters of Authorization (SELOAs) for 7,570 MW of load.[51] The SELOA stage is where the customer has requested the Company begin an engineering study of what is required to serve customer load.

ESAs represent an appropriate milestone for constructing generation while CLOAs and SELOAs do not represent a sufficient level of commitment or investment by a data center customer to risk ratepayer funds. Dominion states that signed energy service agreements (ESAs) cover load projections through the early 2030s. But beyond 2032, Dominion's data center load forecast includes nearly 6 GW of prospective load that does not currently have ESAs.[52]

49 Dominion 2024 IRP at 14 (Corrected).

50 *Id.*

51 *Id.*

52 Dominion 2024 IRP, Appendix 2A at 5.

Dominion should be clearly differentiating between generation resources built to serve committed load with ESAs and generation planned to serve prospective load that is less likely to materialize. The company could do this by developing a baseline load forecast that only includes load from data centers with an ESA, and a separate "high data center load" projection that includes more speculative load without an ESA, weighted based on the prospective data center customer's stage of development.

Q Does the data center load outlined in Dominion's IRP reflect the Company's most up-to-date understanding of its future data center load forecast?

A No. On February 12, 2025, Dominion released an updated data center load forecast as part of its Q4 2024 earnings call.[53] The Company's updated data center forecast showed a jump in total data center contracted capacity from 21.4 GW total in its July 2024 forecast to 40.2 GW total in its December 2024 forecast. Very little of the shift was in the ESA or CLOA stage, and instead the majority of this load is in the SELOA stage (26.2 GW in the December 2024 forecast vs. 7.6 GW in the July 2024 forecast).

Q How does this increased forecast impact your recommendations?

A It doesn't. The Company cannot continue to approach data center load in the same way as every other customer with an "obligation to serve" regardless of the impact on system reliability and other ratepayer bills. Ratepayer protection must be central to the Company's planning and procurement. Dominion should be identifying individual

53 Dominion Energy, *Q4 2024 Earnings Call* (February 12, 2025), available at https://bit.ly/43i9IFq.

customers and agreeing to include their load in the IRP only if the Customer is willing to negotiate a contract that has them take on their full cost to serve.

Q How does Dominion's resource plan impact its resource planning decisions and its ratepayers?

A As discussed above, data center demand has caused Dominion to abandon its plan to retire several of its aging coal and gas plants.[54] Previously, Dominion planned to retire the Clover coal plant in 2025 and several gas plants in the later 2020's. But in the 2023 IRP the Company pushed Clover's retirement date to 2040 and now the current 2024 IRP, Dominion has decided to keep all its existing fossil units online throughout at least 2045.

The incremental load from data centers does not inherently make the coal plants less costly to operate—in fact it should have minimal impacts on the costs to operate the coal plants.[55] Instead, with higher demand and limited supply in the present—and real-world limits on how much can be built out each year to meet demand—energy and capacity markets become more constrained and prices go up. Dominion has to turn to more costly resources further up the supply stack to meet demand which in turn increases system costs. This means that absent action from the Commission to protect existing ratepayers from the cost to maintain legacy resources that would not be needed

54 Dominion 2020 IRP at 28.

55 There could be some impacts on the coal market.

but for the data centers, system costs will increase for all customers—not just data centers.

Another concern is that Dominion's legacy resources, especially coal plants, have high operating costs, making them relatively uneconomic not sources of energy. They also are not nimble or fast ramping which means they are not well suited to facilitate the integration of renewables, particularly solar PV, that Dominion's own modeling shows is the most economic source of energy. Dominion's decision to maintain its legacy fossil units to meet data center capacity needs is therefore undermining its ability to build-out low-cost solar PV to provide zero-marginal cost energy. This is concerning given that there are capacity resources—such as BESS and CTs—that are able to both provide capacity and support the integration of renewable resources.

Q Has Dominion conducted any economic analysis on its existing fossil units?

A Yes, as part of its current and prior IRPs the Company conducts a cash flow analysis for each existing unit that compares unit performance relative to the market. In Dominion's 2023 IRP[56]—which included data center growth but did not include the Section 111 Rules—the Company's cash flow analysis showed that, under the low, base, and high capacity price forecasts, VCHEC had a negative cash flow ranging from -$119 to -$305 million over the next ten years. Clover and Mount Storm both also had

56 Dominion 2023 IRP at 72.

negative cash flows under a low capacity price forecast but positive cash flows in the base and high capacity price scenarios.

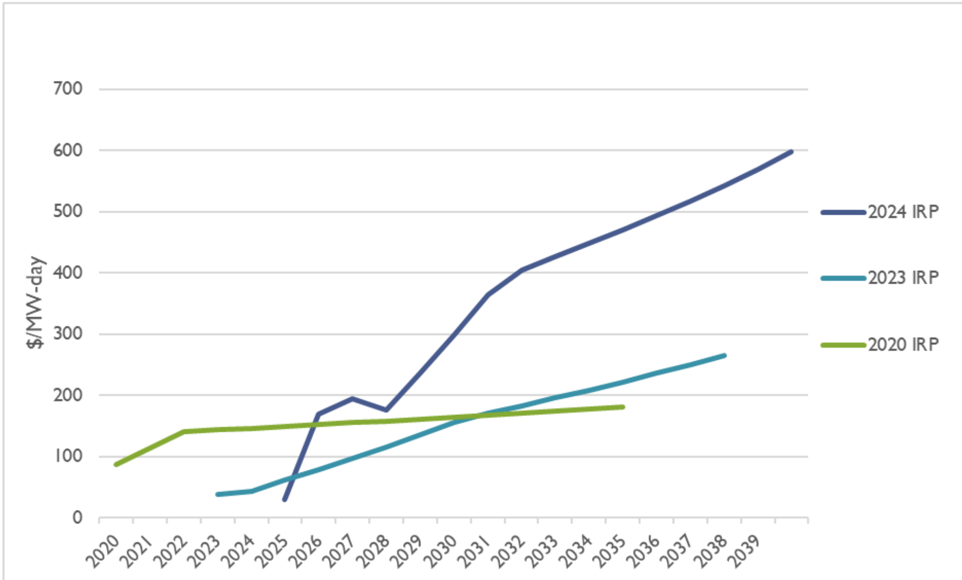
In its current IRP, Dominion's updated analysis finds that all existing fossil units have a positive cash flow over the next 15 years.[57] This is because, as discussed above, increased demand from data centers is expected to drive up market prices and this in turn increases the competitiveness of the existing resources.

Q How is data center load growth expected to impact market prices?

A Dominion's current commodity price forecasts show a large increase in energy prices in the near term and larger increase in capacity prices over the long term (Figure 5) relative to the commodity prices it used in its 2020 and 2023 IRPs. It is this increase in capacity prices that is driving the positive cash-flow economics that Dominion presents in this IRP—not an improvement in the performance of the coal plants. And it is data center load growth across the RTO that is primarily responsible for the increase in capacity prices.

57 Dominion 2024 IRP at 74.

Figure 5: Dominion Capacity Price Forecast, PJM RTO, 2020–2024 IRP Assumptions[58]



Sources: Dominion 2024 IRP, Appendix 5B-11; Dominion 2023 IRP, Appendix 4N; Dominion 2020 IRP, Appendix 4O.

B. Risks to Ratepayers from Continued Fossil Dependence

Q What risks is the Company exposing ratepayers to from its planned expanded dependence on coal, gas, and oil?

A Dominion's intention to maintain and expand its portfolio of gas, oil, and coal resources exposes its ratepayers to fuel price volatility potential for sizeable additional expenses from future regulations.

58 2020 forecast is for Mid-Case Federal CO_2 with Virginia RGGI Commodity Forecast; 2023 forecast is for Base Case Commodity Forecast; 2024 forecast is VCEA with EPA Commodity Forecast.

Q Explain the risks posed to ratepayers by fuel price volatility.

A High reliance on gas resources can expose ratepayers to fuel price volatility for which ratepayers cannot plan. Gas is a global commodity, which means that both domestic and global market forces can impact the price and demand for the resource. After roughly doubling from 2019 to 2023, North American liquid natural gas export capacity is projected to double again by 2028, from current levels of 11.4 billion cubic feet per day to more than 24 billion cubic feet per day in 2028.[59] To put this in perspective, US total gas consumption in 2023 averaged roughly 89 billion cubic feet per day.[60] The global market consumption effect on prices in the United States will continue to increase significantly over even just the next few years.

When the market is constrained and prices spike, those costs are passed directly to ratepayers. This happened recently in 2022 when Russia invaded Ukraine and European gas customers turning increasingly to U.S. gas. This drove up domestic gas prices, and those high costs were passed on directly to ratepayers. For example, DTE Electric Company in Michigan filed its 2022 Fuel Reconciliation Docket and noted that gas spending was 74 percent higher than planned. As a result, DTE requested recover

59 Victoria Zaretskaya, *North America's LNG Export Capacity is on Track to More than Double by 2028*, U.S. Energy Information Administration (December 30, 2028), available at https://bit.ly/4hZcpzW.

60 U.S. Energy Information Administration, *Natural Gas Consumption by End Use* (February, 2025), available at https://bit.ly/3D0A2cp.

an additional $154 million for 2022 fuel costs alone.[61] Absent action from the Michigan Commission, DTE and its shareholders are not impacted by these gas price spikes—these costs are entirely passed on to ratepayers. The same phenomenon could happen just as easily in Virginia. Dominion should take this into account in its IRP modeling, and in planning its future resource mix. Reducing its reliance on fossil resources is the best way to protect its ratepayers from these future price volatility risks.

Q What risks does Dominion face from continued reliance on coal assets?

A The coal market has seen dramatic price volatility in some parts of the United States over the past few years.[62] There have also been labor challenges both at the mines and the railroad companies that transport the coal, as coal workers demand better pay and have more options in the labor market. Additionally, as more and more coal plants across the United States retire and the demand for coal contracts, coal companies could consolidate. Concentration of the coal of supply in a few companies means more less competition, which in turn can lead to higher coal prices.[63]

Electric power sector coal consumption was down in 2023 relative to prior years and accounted for around 15 percent of generating capacity and 16 percent of total utility-

61 *Application of DTE Electric Company for Reconciliation of its Power Supply Cost Recovery Plan*, Michigan Public Service Commission Case No. U-21051, DTE Electric Exhibit No. A-7 (March 31, 2023), available at https://bit.ly/43h5pKn.

62 U.S. Energy Information Administration, *Coal Markets*, https://www.eia.gov/coal/markets/.

63 Duke Energy, *2023 Carolinas Resource Plan*, Appendix F: Coal Retirement Analysis (2023), available at https://bit.ly/4h4RwlL.

scale generation.[64] Preliminary data from EIA indicates that this trend continued in 2024.[65] This is novel because coal's national market share of electric generation had been around 20 percent each month between 2020–2022; and prior to 2020, coal had never comprised less than 20 percent market in any month.[66] Additionally, risks from increased environmental regulation, as we will discuss next, could result in higher costs and higher risks. Higher risk impacts not just resource planning economics but company risk profiles which can lead to downgraded credit ratings, and that can impact access to capital.

Q How does Dominion's build plan impact regulatory uncertainty and risk to environmental compliance?

A The cost of operating Dominion's existing fossil resources is still high and the regulatory risk they face is real. Coal units will continue to face uncertain regulatory and environmental compliance costs from existing federal and state rules, and new rules further out into the future. This regulatory uncertainty poses a substantial risk to ratepayers. The Section 111 Rules may be repealed in their current form. But while prior administrations have weakened the Section 111 programs designed by their

64 U.S. Energy Information Administration, *Electricity Explained* (July 16, 2024), available at https://bit.ly/41bLNVm.

65 U.S. Energy Information Administration, Form EIA-923 Detailed Data, https://www.eia.gov/electricity/data/eia923/ (accessed February 24, 2025).

66 Institute for Energy Economics & Financial Analysis, *Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024* (November 2, 2023), available at https://bit.ly/43fuBB5.

predecessors, they have nonetheless acknowledged a continuing duty to implement some form of federal carbon regulation.[67] Given that some form of carbon regulation is likely even at the federal level during the modeled study period, the current Section 111 Rules serve as a reasonable proxy for the combined effect of federal and state programs—including Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI)—that substantially increases the cost of dispatching and operating carbon-emitting resources.[68]

Q Is Dominion facing other regulations at the state or federal level?

A At the state level, the VCEA mandates the retirement of carbon-emitting units by 2045. This is beyond the IRP's 15-year study period, but it is also not something the Company appears to be considering or planning for.

On the federal level, U.S. EPA has set a more stringent Mercury and Air Toxics Standards (MATS) Rule to strengthen the filterable particulate matter emission standard from 0.030 pounds per million British thermal of heat input (lb/MMBtu) to 0.010 lb/MMBtu for all existing coal-fired electric utility steam generating units.

67 *See generally* Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, 84 Fed. Reg. 32520 (July 8, 2019).

68 As discussed in Sierra Club & NRDC Witness William Shobe's testimony, litigation over Virginia's participation in RGGI is ongoing.

Compliance is required by July 8, 2027.[69] U.S. EPA has already determined that plants such as Mount Storm that use electrostatic precipitators to control particulate matter will need to upgrade their electrostatic precipitators to comply with the 0.010 lb/MMBtu standard; they will also have to install fabric filters to comply with the 0.006 lb/MMBtu standard.[70] At a minimum, Dominion will need to implement potentially costly upgrades to comply with this standard and may need to install a new baghouse at Mount Storm, which would require major capital investments. Mount Storm is, in fact, one of only a few plants in the United States that will not be able to meet the proposed standard without upgrades.

In addition, in May 2024, U.S. EPA finalized revisions to the 2015 and 2020 Steam Electric Effluent Limitations Guidelines and Standards Rule (2024 ELG Rule).[71] This rule regulates combustion residual leachate (CRL) discharge from active coal stations by imposing a zero-discharge requirement.[72] Dominion claims the bottom ash transport water system it is currently installing should meet the zero-discharge requirement, but the Company may have to make additional upgrades to comply with the CRL discharge

69 National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed Reg. 38508 (May 7, 2024).

70 Environmental Protection Agency, *2023 Technology Review for the Coal- and Oil-Fired EGU Source Category* (2023), available at https://bit.ly/3Mij2yR.

71 Supplemental Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40198 (May 9, 2024).

72 Dominion 2024 IRP, Appendix 5A at 3–4.

requirements.[73] Admittedly, those CRL upgrades will be required regardless of when Mount Storm retires. But the 2024 ELG Rule illustrates that, even if environmental regulations proceed in fits and starts, U.S. EPA is continuing over the long term to rein in the disproportionate environmental footprint of coal-fired generation. It also highlights the importance of transparent, forward-looking decision-making for plants subject to increasingly stringent regulations.

Dominion stated that it would cost approximately $1.5 billion for the Mount Storm coal plant to comply with the MATS and 2024 ELG rules.[74] The Company also included costs for ELG compliance at Clover and VCHEC—for Clover, these totaled around $34 in capital costs and $2 million in annual ongoing O&M costs.[75] Dominion did not provide exact costs for VCHEC but indicated that it calculated VCHEC costs based on the Clover costs provided in discovery. Many of these expenses are avoidable with early retirement.

Q How does the projected data center load growth impact Dominion's RPS requirement?

A As load grows, so does Dominion's RPS obligation. Relative to the 2024 IRP, in its 2020 IRP, Dominion forecasted much lower growth in future load, with

73 Dominion 2024 IRP, Appendix 5A.

74 Company's Response to Sierra Club Discovery Request No. 1-22b, attached as Exhibit DG-8.

75 Company's Response to Sierra Club Discovery Request No. 1-22, Attachment Sierra Club Set 01-22(c), attached as Exhibit DG-9.

correspondingly less renewable generation needed to meet RPS requirements. As a result of the load increases in the 2024 IRP, Dominion has also modeled an increase in renewable builds needed to meet its RPS requirements. To meet those requirements, Dominion must either build out large amounts of renewables, buy renewable energy credits (REC) from a third party, or make significant deficiency payments. Dominion's modeling shows that none of its portfolios are on track to comply with RPS obligations in 2025-2026.[76] Beyond 2026, Dominion is planning to rely on large amounts of purchased RECs for compliance in all portfolios.[77]

Q What other aspects of the VCEA will be challenging to meet with Dominion's current resource plan?

A It is unclear how Dominion plans to comply with the requirement to retire all fossil generation by 2045 since its modeling ends in 2039. Also, given Dominion's significant investments in new gas, compliance will likely entail substantial stranded assets. In Dominion's VCEA with EPA portfolio, the Company continues to rely on carbon-emitting resources (natural gas) for 28 percent of its generation by 2039.

76 2024 IRP at 62.

77 *Id.*

C. Cost of Incremental Firm Gas & Transmission Costs

Q What risks does Dominion face from reliance on gas resources?

A As discussed above, firm gas pipeline capacity is constrained in GPC's service area. That means that unless an expensive new pipeline is built, the Company does not have a firm source of gas to supply new gas resources. Any new gas resource without a firm supply of fuel is not actually a firm resource unless it can also operate on oil.

Q Has Dominion calculated the costs associated with building out additional firm gas capacity to serve new gas generation resources?

A It does not appear so. The Company indicated in its IRP that the Company's gas-fired generation fleet is located in a fully subscribed pipeline corridor with pipeline constraints and associated restrictions.[78] That means that unless an expensive new pipeline is built, the Company does not have a firm source of gas to supply new gas resources. Dominion also indicated that it is reviewing proposals for additional firm transportation, pipeline storage, peaking services, and onsite fueling.[79] Any new gas resource without a firm supply of fuel is not actually a firm resource unless it can also operate on oil.

To incorporate a cost, Dominion could, for example, add a $/MMBtu adder for to represent the more costly "firm" supply for new plants. Duke uses a similar

78 Dominion 2024 IRP, Appendix 5B at 1-2; Company's Response to Commission Staff Discovery Request No. 7-154(k), Attached as Exhibit DG-10.

79 *Id.*

methodology in its IRP in North Carolina, in which it models an adder of $1.50/MMBtu to represent the cost of firm gas capacity. This methodology was used by NREL for a study the lab did on behalf of Duke Energy for its carbon-free integration study,[80] as well as by Duke University in a report for the state of North Carolina that included both Dominion and Duke Energy as working group members.[81]

Q How is Dominion addressing the lack of firm gas capacity in its modeling?

A Dominion assumes that new CTs will operate on oil-only in winter given the constraints in their gas pipelines.[82] Compared to gas-fired operation, oil-fired operation is four-to-six times more expensive and has higher emissions. Overall, reliance on oil is a bad long-term strategy—especially when there are cost-effective, lower-cost, and lower-risk alternatives.[83] The Company indicated that, while it is regularly communicating with and engaged with the pipeline operations and operators, it does not currently have a contract for firm capacity necessary to serve the planned new gas plants. Additionally, Dominion has not and is not leading a formal study on the issue of whether it has sufficient firm pipeline capacity to serve the gas build-out modeled in its portfolio and

80 Brian Sergi *et al.*, *Duke Energy Carbon-Free Resource Integration Study*, NATIONAL RENEWABLE ENERGY LABORATORY (2022), available at https://bit.ly/3XocYLv.

81 Kate Konschnik *et al.*, *Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina* (2021), available at https://bit.ly/4iiVuIi.

82 Dominion 2024 IRP, Appendix 5B at 1-2.

83 Dominion 2024 IRP, Appendix 5B-1.

has no plan to.[84] It is concerning that Dominion does not appear to be incorporating into the 2024 IRP estimates of the incremental cost that firm pipeline capacity may impose on its system.

Q Has Dominion calculated the incremental costs of transmission required to serve the projected data center load over the planning period?

A No. In calculating the portfolio NPVs, Dominion includes a flat $22.4 billion in transmission build-out costs for all portfolios it modeled.[85] The Company indicates that this is simply a "high level" cost estimate based on a prior Commission order[86] calculated using generic cost assumptions.[87] It is unclear how much of this $22.4 billion is incremental transmission attributed to data center and how much is attributed to non-data center needs.

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84 Company's Response to Commission Staff Discovery Request No. 3-100, Attached as Exhibit DG-11.

85 Dominion 2024 IRP at 66, Table 5.2.2.

86 Company's Response to Clean Virginia Discovery Request No. 2-2, attached as Exhibit DG-12.

87 Company's Response to Commission Staff Discovery Request No. 5-134(e), attached as Exhibit DG-13.

Q What information has Dominion provided on transmission projects needed for data center load?

A Dominion identified $7.6 billion in transmission projects that are currently underway or planned.[88] In a supplemental filling provided at the order of the Commission, Dominion provided a breakdown of the $7.6 billion in planned projects and identified which were attributed to data center load.[89] Less than a quarter of the $7.6 million was for non-data center transmission projects. The Company confirmed that the $22.4 billion estimate for the planning period includes the $7.6 billion in planned projects. However, the Company did not provide any detail related to the remaining $14.8 million in transmission spending over the planning period.

This means that the Company did not fulfill the Commission's request to show the cost of its portfolios with and without data center load growth. The lack of clarity on how the future transmission costs were calculated and how much are attributed to data center load growth (i.e., would not be present in the scenario without data center load) over the entire planning period is concerning given the magnitude of costs at issue and the importance of protecting ratepayers from unnecessary costs. Table 12 below shows what we know and what we do not know about the Company's transmission plans. Given the detail Dominion has provided on its planned data center spending, we estimate that over the planning period, as much as $7.2 billion (of the total $22.4

88 See Exhibit DG-12.

89 Dominion 2024 IRP, SCC Directed 2024 IRP Supplement.

billion) is entirely attributed to data center load and another $9.8 billion is at least partially attributed to data center load. Given the size of these numbers, it is concerning that Dominion has not provided a breakdown of the entire $22.4 billion in transmission costs.

Table 12. Transmission Cost Estimates

Project Type	Planned Tx Projects ($M)	Tx Projects Included in NPV ($M)	Incremental ($M)
Data Center-Driven	$2,435	No information	No Information
Not Data Center-driven	$1,830	No information	No information
Mixed Drivers	$3,329	No information	No information
Total	$7,595	$22,400	$14,805

Source: Dominion 2024 IRP, Supplemental Appendix 2C-2

6. STRATEGIES TO PROTECT NON-DATA-CENTER RATEPAYERS FROM DATA CENTER GROWTH

Q What can the Commission do to protect ratepayers from data center load growth?

A Dominion should not build resources to serve speculative and prospective load that does not yet have an ESA. The Commission should not approve Dominion's plan to build to serve the data center load growth without a clear commitment from the Company (in the form of a proposed alternative tariff, for example) that the data centers being served will cover the full costs they are imposing on the system. This includes an understanding of the incremental transmission and firm gas capacity costs.

This is especially important because Dominion's current statements indicate opposition to treating the data centers differently than any other customer. In its supplemental filing, Dominion expressed opposition to isolating the impact of the data center load from other customers.[90] Dominion has an obligation to serve but it also has an obligation to protect its existing non-data center customers from unnecessary cost increases. Data center load is large and disruptive and entirely unique from the types of load Dominion has traditionally dealt with in the magnitude and timing of demand. It is also unique in the potential for creating stranded assets if the prospective load never materializes or does not stay on the system for the long term.

Other utilities around the country facing similar challenges with data center load are developing novel tariffs and agreements with the data centers to ensure that existing ratepayers are protected. Dominion should develop alternative tariff options for data center customers that address both risk and enable deployment of increased renewable energy. Dominion should require commitment to an alternative tariff as a pre-condition for including new data center load in its modeling the near term (e.g., in the next five years). Finally, the Company should be evaluating the revenue requirement and bill impacts of the new load with alternative tariff structures in place.

Q Why should the Commission consider tariff design in an IRP docket?

A While tariffs are often addressed in rate cases and certificate of public convenience and necessity dockets, they can also be highly relevant to resource planning. A customer's willingness to enter into such a tariff should be a precursor for Dominion planning to

90 SCC Directed 2024 IRP Supplement at 1.

serve that large load as part of its resource plan. If a data center customer is not willing to receive service under a tariff that shifts some of the cost and risk to the customer—rather than placing it all on existing ratepayers—then Dominion should not build generation and transmission to meet that customer's demand. There are two general types of tariffs relevant here: tariffs to protect existing ratepayers from high system costs and tariffs to incent the data center customers to be cleaner and more flexible.

Q What are the general principles common to these tariffs?

A Some general principles for data center tariffs include:

- Requirement that load over a certain MW threshold—as measured at an individual facility, or across multiple facilities owned by the same company—be on a specific data center or similar large load customer tariff;
- Commitment to pay the cost of incremental generation not needed "but for" the data center for a substantial portion of the asset life;
- Minimum take requirements/ minimum monthly demand based on contracted capacity, minimum contract term (years), and exit fees;
- Demand response, demand flexibility, interruptible load, EE potential as applicable;
- Commitment to develop renewable energy resources consistent with jurisdictions goal as well as Company's corporate commitments through clean energy tariffs, for example;
- Payment of incremental costs to build out distribution, transmission and firm gas infrastructure;
- Additional investment in community, economic development and low-income programs.

These and other principles are discussed in more detail in recent industry and expert reports.[91]

Q Do you have any examples of data center tariffs designed to protect customers?

A Yes, below are several examples of existing and proposed data center tariffs.[92]

- American Electric Power Company (AEP)'s Indiana Michigan Power Company (I&M) introduced a settlement in Indiana with Amazon and Google.[93] Settlement includes the following terms:
    - Applies to individual facilities of 70 MW or larger, of 150 MW or aggregated load across a Company.
    - 12-year contract with a minimum monthly charge. The contract has a five-year ramp up period. Contract capacity can be reduced by up to 20 percent with 42 months' notice and can be reduced above 20 percent up to termination with an exit fee.
    - Several IRP and study provisions including evaluation of GETs, and evaluation of demand-response opportunities.
    - Agreement by I&M to collaboratively develop a clean transition tariff (CTT) that supports clean energy investments while ensuring program costs are covered by the customer to be filed by October 1, 2025.
    - Contribution by each of Amazon, Microsoft, and Google of $500,000 per year for five years to Indiana Community Action Associate to support health and safety weatherization for income qualified customers.

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91 *See, e.g.,* Stacy Sherwood, *Review of Large Load Tariffs to Identify Safeguards & Protections for Existing Ratepayers*, Energy Futures Group (January 28, 2025), available at https://bit.ly/3F05yrs; Winson *et al.*, supra note 47.

92 I am not endorsing any of these, but using them strictly as an example of the type of tariff the Commission and Dominion could consider.

93 Sherwood, *supra* note 91; *Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff*, Indiana Utility Regulatory Commission Cause No. 46097, Submission of Unopposed Settlement Agreement & Unopposed Motion for Acceptance of Out of Time Filing (November 22, 2024), available at https://bit.ly/3F8Cpu8.

- AEP Ohio submitted an application for approval of a new data center tariff.[94] This docket is ongoing and the utility and the large data center customers (including Amazon, Google, and Meta) are not yet in agreement on the tariff terms. AEP seeks a moratorium on connecting new data center load until a tariff is approved. The Company's proposal includes the following:
  - Applies to data center customers with single or aggregate Company load above 25 MW.
  - Minimum 10-year service contract with minimum demand charge based on 90-95 percent of contracted demand. A three-year ramping period can be negotiated. Exit fee equal to 36 months of charges if customer leaves after 5 years.
  - AEP will procure power for data center customers that choose to receive power under the standard service offer (SSO) under a SSO auction separate from what it uses to procure power for existing customers.[95] This is to protect existing ratepayers from risks and complication from adding additional load to the market.
  - Proposal does not include demand flexibility or any evaluation of clean tariff terms.
- Entergy Louisiana (ELL) is building three new Combined Cycle Combustion Turbine generators totaling 2,262 MW and investing in substantial new transmission facilities and transmission upgrades to serve Meta data centers in Northern Louisiana.[96] This case is ongoing and the details are being negotiated, but in ELL's application,[97] the Company detailed the following:
  - Energy service agreement (ESA) with a 15-year term.

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94 *Application of Ohio Power Company for New Tariffs Related to Data Centers & Mobile Data Centers*, Ohio Public Utilities Commission Case No. 24-508-EL-ATA, Application for Approval of New Tariffs by Ohio Power Company (May 13, 2024), available at https://bit.ly/3PC03RH.

95 AEP Ohio is a distribution utility and does not own generation in the state. In Ohio, distribution utilities serve load by procuring power through a central Standard Offer Service (SSO) auction.

96 *Application of Entergy Louisiana, LLC for Approval of Generation and Transmission Resources Proposed in Connection with Service to a Significant Customer Project in North Louisiana etc.*, Louisiana Public Service Commission Docket No. U-37425, Application at 12 (October 30, 2024), available at https://bit.ly/4bkxMJv.

97 *Id.* at 4–5.

- Contribution in Aid of Construction (CIAC) agreement whereby the Customer will cover certain transmission-related facilities as well as other contributions (although notable, the Customer is not covering all the transmission costs).
- Large Load, High Load Factor Power Service Rate Schedule (Rate Schedule LLHLFPS-L), where the customer will pay (1) minimum monthly charges that cover, during the fifteen-year term of the ESA, the full annual revenue requirement for the generators; (2) the customer's allocated share of all fixed and variable costs in ELL's formula rate plan and all associated riders (including storm securitization and resiliency riders).
- Corporate Sustainability Rider (CSR) agreement with customer commitment to pay for 1,500 MW of solar and/or storage and a matching $1 million contribution by the customer to Entergy's Power to Care Program that provides financial assistance to low income customers.
- Proposal includes no clean tariff or demand flexibility terms.

- Appalachian Power Company and Wheeling Power Company in West Virginia,[98] and Kentucky Power Company in Kentucky[99] both filed changes to their large industrial tariffs schedules. A joint stipulation and settlement was filed in the dockets with Google as a party,[100] but the Commissions have not ruled on either case yet. The filed changes in both cases include the following:
  - In West Virginia, Schedules LCP and IP were revised to cover load over 200 MW. In Kentucky, Tariff Industrial General Service was revised to cover load greater than 150 MW.
  - Contract period of 20 years with requirement of five years written notice to discontinue service. Exit fee within first five years is equivalent to five years billing. Five years notice is required to reduce capacity by up to 20 percent.
  - Monthly minimum demand of 90 percent contracted capacity.

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98 *Application of Appalachian Power Company & Wheeling Power Company for Approval of Revisions to Schedules LCP & IP*, West Virginia Public Service Commission Case No. 24-0611-E-T-PW, Application (July 18, 2024), available at https://bit.ly/41m2ltW.

99 Kentucky Power Company, First Revised Tariff Sheet Nos. 1-1 & 8-2 and Original Tariff Sheet No. 8-3 (August 30, 2024), available at https://bit.ly/4hY1Ugf.

100 *Application of Appalachian Power Company & Wheeling Power Company for Approval of Revisions to Schedules LCP & IP*, West Virginia Public Service Commission Case No. 24-0611-E-T-PW, Joint Stipulation & Agreement for Settlement (January 22, 2025), available at https://bit.ly/3QDgWw8.

Q Are there examples of green tariffs designed to allow data centers to access clean renewable energy?

A Yes, I provide two examples, one from Duke Energy in the Carolinas and one from Nevada Energy (NV Energy).

- NV Energy and Google have jointly proposed a CTT.[101] The CTT allows Google to select its power supplier, but it must do so for the life of the project and cover any premium compared to what NV Energy would have procured to serve the load.
    - Opt-in rate for large customers over 5 MW in load.
    - Customer selects a renewable resource portfolio in coordination with the Company. NV Energy signs a PPA with the selected resource and passes the cost directly to the customer (called a "sleeved" PPA).
    - Customer pays for the cost of the resource through an hourly fixed charge during the hours the CTT resources are producing energy, and avoids energy charge during those hours.
    - Customer still pays other grid charges for all hours.
- Duke Energy Carolinas clean energy tariffs
    - Duke signed a memorandum of understanding (MOU) with Amazon, Google, Microsoft, and Nucor for a program called Accelerating Clean Energy (ACE) tariffs. The ACE tariffs would allow Duke to offer carbon-free energy to new commercial & industrial customers and protecting other ratepayers from the program costs.[102] Program involves a CCT and minimum take requirement.[103] This tariff has not yet been filed with the NCUC for approval.
    - North Carolina Utilities Commission approved the green tariff Green Source Advantage Choice Program in July 2024. Tariff applies to non-residential

101 *Application of Nevada Power Company for Approval of Clean Transition Tariff*, Nevada Public Utilities Commission Docket No. 24-05022, Application for Tariff Approval (May 21, 2024), available at https://bit.ly/43ht3Xk.

102 DUKE ENERGY, *Responding to Growing Demand, Duke Energy, Amazon, Google, Microsoft, and Nucor Execute Agreements to Accelerate Clean Energy Options* (May 29, 2024), available at https://bit.ly/4iejegO.

103 Winson *et al.*, *supra* note 47.

customers over 1 MW and allows Duke to procure renewable energy on their behalf.[104]

Q What are your main takeaways from this IRP and the resource planning modeling the Company performed?

A Dominion is facing projections of large data center load growth for its service territory over the next several decades. In response, the Company is planning to maintain its aging and uneconomic legacy plants and build out an enormous quantity of new resources. The Company is also facing challenges with VCEA compliance, uncertain federal regulations of fossil fuel plants and incentives for renewable deployment, a renewable industry recovering from a period of supply chain challenges and record inflation, and interconnection backlogs in PJM delaying renewable deployment in the region. Meanwhile, the natural gas generation industry is facing substantial supply chain challenges, as well as fully subscribed regional pipelines. All of these factors make the current planning environment more uncertain and unstable.

Dominion should critically evaluate the findings from its IRP and act to protect its existing ratepayers from the impacts of its data center load. Dominion's 2024 IRP modeling results show that the model builds the maximum quantity of solar and battery storage as soon as it is allowed. Dominion should therefore be issuing RFPs for

104 *Petition of Duke Energy Progress & Duke Energy Carolinas Request Approval of Green Source Advantage Choice Program & Rider GSAC*, North Carolina Utilities Commission Docket No. E-2, SUB 1314, Order Accepting Stipulation & Approving Modified Green Source Advantage Choice Program With Conditions (July 31, 2024), available at https://bit.ly/3DarlMB.

renewables and storage and building out as much of these cost-effective resource as it can based on the competitive bids. To protect ratepayers from the cost of the data center buildout, Dominion should be working with customers and the Commission to proactively develop tariffs that both protect existing ratepayers and incent the development of clean renewable energy resources necessary for VCEA compliance.

Q Does this conclude your testimony?

A Yes.

INDEX OF EXHIBITS

Exhibit No.	Description of Exhibit
Exhibit DG-1	Resume of Devi Glick
Exhibit DG-2	Company's Response to Commission Staff Discovery Request No. 2-70
Exhibit DG-3	Company's Response to Commission Staff Discovery Request No. 9-180
Exhibit DG-4	Company's Response to Commission Staff Discovery Request No. 8-164
Exhibit DG-5	Company's Response to Commission Staff Discovery Request No. 3-86
Exhibit DG-6	Company's Supplemental Response to Staff Discovery Request No. 8-170
Exhibit DG-7	Company's Response to Commission Staff Discovery Request No. 1-41
Exhibit DG-8	Company's Response to Sierra Club Discovery Request No. 1-22(b)
Exhibit DG-9	Company's Response to Sierra Club Discovery Request No. 1-22, Attachment 1-22(c)
Exhibit DG-10	Company's Response to Commission Staff Discovery Request No. 7-154(k)
Exhibit DG-11	Company's Response to Commission Staff Discovery Request No. 3-100
Exhibit DG-12	Company's Response to Clean Virginia Discovery Request No. 2-2
Exhibit DG-13	Company's Response to Commission Staff Discovery Request No. 5-134(e)

EXHIBIT DG-1

Resume of Devi Glick

Synapse Energy Economics, Inc.

Devi Glick, Senior Principal

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7050
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.

- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

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State of Vermont Public Utility Commission (Case No. 24-2945-PET): Direct testimony of Devi Glick in Petition of VT Real Estate Holdings 2 LLC ("Fair Haven Solar") for a Certificate of Public Good, pursuant to 30 V.S.A. § 248, authorizing the installation and operation of a 20 MW solar electric generation facility off Airport Road in Fair Haven, Vermont to be known as the "Fair Haven Solar Project". On behalf of VT Real Estate Holdings 2 LLC. September 17, 2024

Public Service Commission of South Carolina (Docket No. 2024-203-E): Direct Testimony of Devi Glick in Application of Kingstree East 230 for a certificate of environmental compatibility and public convenience and necessity for the construction and operation of a 249 MW AC solar and battery facility in Williamsburg County, South Carolina Pursuant to S.C.Code Ann. § 58-33-10 et. Seq., and request to proceed with initial construction work, S.C. Code Ann. § 58-33-110(7). On behalf of Kingstree East 230 LLC. August 9, 2024.

Indiana Utility Regulatory Commission (Cause No. 46038): Direct Testimony of Devi Glick in Petition of Duke Energy Indiana, LLC Pursuant to Indiana code §§ 8-1-2-42.7 and 8-1-2-61, for authority to modify its rate and changes. On behalf of Citizens Action Coalition of Indiana, Inc. July 11, 2024.

State of Vermont Public Utility Commission (Case No. 23-1447-PET): Rebuttal testimony of Devi Glick in the Petition of VT Real Estate Holdings 1 LLC for a Certificate of Public Good, pursuant to 30 V.S.A. § 248, for a 20 MW ground-mounted solar array in Shaftsbury, Vermont. On behalf of VT Real Estate Holdings 1 LLC ("Shaftsbury Solar"). Revised June 27, 2024.

State of Vermont Public Utility Commission (Case No. 23-1447-PET): Direct testimony of Devi Glick in the Petition of VT Real Estate Holdings 1 LLC ("Shaftsbury Solar") for a Certificate of Public Good, pursuant to 30 V.S.A. § 248, authorizing the installation and operation of a 20 MW solar electric generation facility off Holy Smoke Road in Shaftsbury, Vermont to be known as the "Shaftsbury Solar Project". On behalf of VT Real Estate Holdings 1 LLC ("Shaftsbury Solar"). Revised June 27, 2024.

Iowa Utilities Board (RPU-2023-002): Supplemental Testimony of Devi Glick in re: Interstate Power and Light Company, Proposed Rate Increase. On behalf of Environmental Intervenors. June 21, 2024.

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Michigan Public Service Commission (Case No. U-21051): Direct Testimony of Devi Glick in the Matter of the application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-21050) for the 12 months ended December 31, 2022. On behalf of Michigan Environmental Council. March 8, 2024.

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Louisiana Public Service Commission (Docket No. U-36923): Direct Testimony of Devi Glick in the Application of Cleco Power LLC for: (1) Implementation of changes in rates to be effective July 1, 2024; and (2) extension of existing formula rate plan. On behalf of Sierra Club. February 5, 2024.

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Public Service Commission of South Carolina (Docket No. 2023-154-E): Surrebuttal Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. November 17, 2023.

Public Utilities Commission of Ohio (Case No. 21-477-EL-RDR): Direct Testimony of Devi Glick in the Matter of the OVEC Generation Purchase Rider Audits Required by 4928.148 for Duke Energy Ohio, Inc. the Dayton Power and Light Company, and AEP Ohio. On behalf of Union of Concerned Scientists and the Citizens Utility Board. October 10, 2023.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Direct Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. September 22, 2023.

Public Utilities Commission of Ohio (Case No. 20-165-EL-RDR): Direct Testimony of Devi Glick in the matter of the review of the Reconciliation Rider of the Dayton Power and Light Company. On behalf of Office of the Ohio Consumers' Counsel. September 12, 2023.

Virginia State Corporation Commission (Case No. PUR-2023-00066): Direct Testimony of Devi Glick in re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Virginia Code to §56-597 *et seq.* On behalf of Sierra Club. August 8, 2023.

Public Utility Commission of Texas (PUC Docket No. 54634): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. August 4, 2023

Arizona Corporation Commission (Docket No. E-1345A-22-0144): Surrebuttal Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. July 26, 2023.

Arizona Corporation Commission (Docket No. E-01345A-22-0144): Direct Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. June 5, 2023.

Virginia State Corporation Commission (Case No. PUR-2023-00005): Direct Testimony of Devi Glick in the Petition of Virginia Electric & Power Company for revision of rate adjustment clause, Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 23, 2023.

New Mexico Public Regulation Commission (Case No, 22-00286-UT): Direct Testimony of Devi Glick in the matter of Southwestern Public Service Company's application for: (1) Revisions of its retail rates under advance no. 312; (2) Authority to abandon the Plant X Unit 1, Plant X Unit 2, and Cunningham

Unit 1 Generating Stations and amend the abandonment date of the Tolk Generating Station; and (3) other associated relief. On behalf of Sierra Club. April 21, 2023.

Michigan Public Service Commission (Case No. U-20805): Direct Testimony of Devi Glick in the matter of the Application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ended December 31, 2021. On behalf of Michigan Attorney General. April 17, 2023.

Michigan Public Service Commission (Case No. U-21261): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval to implement a Power Supply Cost Recovery Plan for the twelve months ending December 31, 2023. On Behalf of Sierra Club. March 23, 2023.

New Mexico Public Regulation Commission (Case No. 19-00099-UT / 19-00348-UT): Direct Testimony of Devi Glick in the matter of El Paso Electric Company's Application for Approval of Long-Term Purchased Power Agreements with Hecate Energy Santa Teresa, LLC, Buena Vista Energy, LLC, and Canutillo Energy Center LLC. On Behalf of New Mexico Office of the Attorney General, January 23, 2023.

Arizona Corporation Commission (Docket No. E-01933A-22-0107): Direct Testimony of Devi Glick in the matter of the application of Tucson Electric Power Company for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona for related approvals. On Behalf of Sierra Club. January 11, 2023.

New Mexico Public Regulation Commission (Case No. 22-00093-UT): Direct Testimony of Devi Glick in the amended application for approval of El Paso Electric Company's 2022 renewable energy act plan pursuant to the renewable energy act and 17.9.572 NMAC, and sixth revised rate no. 38-RPS cost rider. On Behalf of New Mexico Office of the Attorney General, January 9, 2023.

Iowa Utilities Board (Docket No. RPU-2022-0001): Supplemental Direct and Rebuttal Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. November 21, 2022.

Public Utility Commission of Texas (PUC Docket No. 53719): Direct Testimony of Devi Glick in the application of Entergy Texas, Inc. for authority to change rates. On behalf of Sierra Club. October 26, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00051): Direct Testimony of Devi Glick in re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Code §56-597 *et seq*. On behalf of Sierra Club. September 2, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilities Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Reply to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Public Utility Commission of Texas (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

Resume updated January 2025

EXHIBIT DG-2

Company's Response to Commission Staff Discovery Request No. 2-70

<u>Virginia Electric and Power Company</u>
<u>Case No. PUR-2024-00184</u>
<u>Virginia State Corporation Commission Staff</u>
<u>Second Set</u>

The following response to Question No. 70 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on December 5, 2024, was prepared by or under the supervision of:

Jarad L. Morton
Manager, Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 70

Please refer to the IRP at Appendix 3B-10, which is titled "Potential Unit Retirements for VCEA with EPA," and has a footnote indicating that the term "Planned Unit Retirements" "[r]eflects retirement assumptions used for planning purposes, not firm Company commitments".

(a) Were any or all of these units projected to retire in 2026 for the purposes of modeling the VCEA with EPA Regulations Portfolio, or were these units still available for selection after 2026?

(b) Were these units retired in 2026 for the purposes of modeling any other Portfolio, or were these units available for selection after 2026?

Response:

(a) and (b) The small CTs shown as potential retirements in Appendix 3B-10 are older units in the Company's fleet that the Company plans to retire at the point the units can no longer be repaired either because parts are not available, or it becomes cost prohibitive. For modeling purposes, consistent with past IRPs, in all Portfolios, these units are all retired in the second year of modeling as they are not counted on to meet future energy and capacity needs.

EXHIBIT DG-3

Company's Response to Commission Staff Discovery Request No. 9-180

Virginia Electric and Power Company
Case No. PUR-2024-00184
Virginia State Corporation Commission Staff
Ninth Set

The following response to Question No. 180 of the Ninth Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on January 21, 2025, was prepared by or under the supervision of:

Jarad L. Morton
Manager, Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 180

For Portfolio 3 and 4, the VCEA with and without EPA Portfolios, was the model required to select new Company owned solar, wind or storage resources? If the answer is yes, please indicate how many MW of nameplate capacity the model was required to select.

Response:

See the Company's response to Sierra Club Set 01-14. In the VCEA Portfolios, the Company only included (*i.e.*, instructed the model to select) solar and energy storage resources to meet the development targets of Va. Code § 56-585.5 D 2. All other resources in those Portfolios and all resources, including carbon or carbon dioxide emitting resources, in the REC RPS Only with and without EPA Portfolios were selected (*i.e.*, least-cost optimized) by the model on an economic basis, if needed for energy and/or capacity. Please see Attachment Staff Set 09-180 (JLM) for a breakdown of VCEA builds versus additional resources selected by the model for both VCEA Portfolios.

EXHIBIT DG-4

Company's Response to Commission Staff Discovery Request No. 8-164

Virginia Electric and Power Company
Case No. PUR-2024-00184
Virginia State Corporation Commission Staff
Eighth Set

The following response to Question No. 164 of the Eighth Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on January 13, 2025, was prepared by or under the supervision of:

Jarad L. Morton
Manager, Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 164

Please confirm or deny the following statements with respect to the Company's modeling in PLEXOS.

(a) The model solves for economic dispatch of resources to meet the load forecast.

(b) The model solves, on a least cost basis, for what resources to build to meet the capacity and energy forecast.

Response:

(a) The model solves for economic dispatch that meets load for each period within the given constraints of each Portfolio including, but not limited to, renewable generation, fuel costs, heat rates, energy import costs, as well as capacity factor limitations and unit outages.

(b) The REC RPS Only Portfolios solve on a least-cost basis. The VCEA Portfolios model compliance with the VCEA's interim development targets for solar, onshore wind, and energy storage resources, and then least-cost optimize the build plan for the other resources that are needed.

EXHIBIT DG-5

Company's Response to Commission Staff Discovery Request No. 3-86

Virginia Electric and Power Company
Case No. PUR-2024-00184
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 86(a), (c), (d), (f), and (g) of the Third Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on December 10, 2024, was prepared by or under the supervision of:

Jarad L. Morton
Manager, Integrated Strategic Planning
Dominion Energy Services, Inc.

The following response to Question No. 86(e) of the Third Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on December 10, 2024, was prepared by or under the supervision of:

Elizabeth A. Willoughby
Environmental Consultant
Dominion Energy Services, Inc.

William A. Coyle
Director – Power Generation Regulated Operations
Dominion Energy Virginia

Aaron Jonas
Manager – Project Construction
Dominion Energy Virginia

The following response to Question No. 86(f), (h), and (i) of the Third Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on December 10, 2024, was prepared by or under the supervision of:

Michael S. Oberleitner
Fuel Commodity Specialist
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 86 of the Third Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on December 10, 2024, was prepared by or under the supervision of:

Nicole M. Allaband
McGuireWoods LLP

Question No. 86

Please refer to the IRP at page 54, which states "For 111(d), the Company modeled compliance by converting the Company's three remaining coal stations to burn natural gas by January 1, 2030, using costs published by the EPA".

a. Please specify which three coal units the Company modeled as converted to natural gas burning facilities.

b. Please provide the unit specific characteristics that were used in the Company's modeling for each station before and after the conversion to gas- fired generation.

c. When the Company conducted its retirement analysis in Figure 5.5.1., were these units analyzed under the assumption that they were coal units as is, or that they had been converted to natural gas-fired facilities?

d. How did the Company account for the cost of the conversions in its NPV analysis in Table 5.2.2?

e. What additional approvals, either at the state or federal level, or through PJM, would the Company need in order to make these conversions?

f. Was onsite fuel back up considered for each of the three units, or access to multiple gas pipelines considered?

g. How did the Company account for the delivery of natural gas to the stations once the conversion was completed?

h. Which of the three stations would require the construction of a new, greenfield, natural gas pipeline?

i. If the answer to (f) is in the affirmative, what is the Company's projection on the length of time for approval of new gas pipeline?

Response:

a. Clover, Mount Storm, and Virginia City Hybrid Energy Center

b. The unit operating parameters used in modeling for Clover, Mount Storm, and the Virginia City Hybrid Energy Center are the same before and after conversion from coal to natural gas. Please see Attachment Sierra Club Set 01-02 (CONF_ES), PLEXOS Inputs (CONF_ES), Operational Data – Existing Resources (JLM) ES.

c. The REC RPS Only Without EPA and VCEA Without EPA Portfolios assumed the three coal stations would continue to operate as is. The REC RPS Only With EPA and VCEA

With EPA Portfolios assumed the three coal stations would be converted to burn natural gas by January 1, 2030.

d. The cost of conversions to natural gas were accounted for by 1) the equipment cost inside the stations to be able to burn natural gas, and 2) the fueling cost of burning natural gas.

e. The Company is still evaluating the necessary approvals that would be needed, but at a high-level, an amendment would be needed to the facility's underlying air permit. Additionally, the Company would likely need to notify PJM of any technical or capacity changes for the units.

f. The Company is continuing to evaluate compliance with the EPA Regulations. These regulations are new, challenged in litigation, and subject to change. For purposes of the 2024 IRP, the Company estimated costs consistent with the those published by the EPA. Generally, the Company will consider backup or alternative fuel sources for natural gas units but specific determinations would depend on factors such as station location, available (current and future) access to pipelines, permitting, etc.

g. The Company used the assumptions published by the EPA for the delivery of natural gas.

h. All three coal stations would require greenfield pipeline laterals off of existing, fully subscribed, interstate pipelines.

i. The Company assumes this question was meant to reference subpart (h) instead of subpart (f). Assuming a favorable regulatory environment, the Company projects it could take 2-3 years for federal approval of a new gas pipeline project.

EXHIBIT DG-6

Company's Supplemental Response to Staff Discovery Request No. 8-170

Virginia Electric and Power Company
Case No. PUR-2024-00184
Virginia State Corporation Commission Staff
Eighth Set

The following **supplemental** response (dated February 13, 2025) to Question No. 170 of the Eighth Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on January 13, 2025, was prepared by or under the supervision of:

Kourtnie E. Sunkins
Regulatory Analyst, III
Dominion Energy Virginia

Shane T. Compton
Director, Integrated Strategic Planning
Dominion Energy Services, Inc.

As it pertains to legal matters, the following response to Question No. 170 of the Eighth Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on January 13, 2025, was prepared by or under the supervision of:

Nicole M. Allaband
McGuireWoods LLP

Question No. 170

Please refer to the Company's Appendix 4A: Virginia Bill Analysis. In the same format as Appendix 4A, including both a "Company Methodology" and "Commission Directed Methodology," please provide a consolidated bill analysis for the SCC Directed 2024 IRP Supplement for both the "No Data Center Load Growth – REC RPS Only with EPA" and "No Data Center Load Growth – VCEA with EPA" Portfolios. Please provide any associated workpapers in Microsoft Excel format with cells and formulae intact.

Response:

The Company objects to this request because it would require original work. Notwithstanding and subject to this objection, the Company provides the following response.

The Company is undertaking and will provide the requested analysis when it is available.

Supplemental Response (dated February 13, 2025):

As stated in the SCC Directed 2024 IRP Supplement, filed on November 15, 2024, Dominion Energy does not have dedicated generation or transmission system resources to serve any class of customers and does not plan to serve customers by class. In addition, as a regulated utility, the Company has an obligation to serve all customers requesting service, including these data center customers. Therefore, ignoring forecasted growth of one type of end-use customer (*i.e.*, data centers) is not a realistic assumption for resource planning. Notwithstanding, in order to model sensitivities to show projected data center load growth removed, as directed by the Commission's October 11, 2024 Order, new assumptions for the load forecast were created. Generally, to show no data center load growth for the sensitivity analysis, the Company froze data center levels at the forecasted 2024 levels. This resulted in model results, when compared to the 2024 IRP, for the REC RPS Only with EPA sensitivity with no data center load growth that had significantly less storage, nuclear, and wind being built and for the VCEA with EPA sensitivity with no data center load growth that had significantly less nuclear and wind being built. The model still chose to build gas fired generation in both sensitivities starting in 2030.

Based on this information, the Company is providing a bill impact analysis for Residential and GS-4 customers that assumes no data center growth for the REC RPS Only with EPA and VCEA with EPA Portfolios in response to question(s) posed by the Commission Staff. The Company is providing a side by side comparison of its originally filed bill impact analysis, filed in the 2024 IRP, with the no data center growth perspective. Overall, the Company Methodology version of the bill analysis shows that residential customers would pay more under a no data center hypothetical scenario in early years, pay less during the middle years, and then ultimately pay more in the last couple years. Without additional data center growth, the models result in (i) fewer combustion turbines, PPAs and storage; (ii) lower RPS requirements; and (iii) the elimination of additional offshore wind and SMR resources. Each of these changes reduce and/or delay costs. The loss of offshore wind reduces costs for constructing the resources, however, the customers lose the benefits (capacity, fuel) associated with those facilities. This is especially true in the out years of 2038 and 2039 when the original build plan has those resources fully functioning. Additionally, the analysis shows that assuming no data center growth, results in residential customers being allocated a greater share of the costs associated with the existing resources.

The Directed Methodology requires the Company to use constant class allocation factors across time and no sales growth, either at the system or class level, in its calculations. The Company believes that this methodology overstates bill projections for the residential customer class because it does not reflect anticipated growth in sales, which is not expected to be uniform between classes, and shifts cost allocation as a result. In addition, the proportion of costs allocated to the residential class is projected to decrease over time because of growth of energy sales to other customer classes. Nevertheless, the Company is also providing results for bill impact analysis that assumes no data center growth showing the Directed Methodology as requested by Commission Staff.

See Attachment Staff Set 08-170(1) (KES) SUPP for the bill analysis results for the REC RPS Only with EPA (No Data Center Load Growth) and VCEA with EPA (No Data Center Load

Growth) Sensitivities. See Attachment Staff Set 08-170(2) (KES) SUPP for a side by side comparison to the originally filed bill impact analysis. See Attachment Staff Set 01-70(3) (KES) SUPP ES for the workpapers.

Attachment Staff Set 07-170(3) (KES) SUPP ES is entirely extraordinarily sensitive (Projected Rate Model) and is being provided pursuant to the being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information dated November 19, 2024, the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Customer Names Information dated December 10, 2024, any additional protective order or ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and the Agreements to Adhere executed pursuant to such orders or rulings.

EXHIBIT DG-7

Company's Response to Commission Staff Discovery Request No. 1-41

Virginia Electric and Power Company
Case No. PUR-2024-00184
Virginia State Corporation Commission Staff
First Set

As it pertains to supply chain and construction, the following response to Question No. 41 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on November 15, 2024, was prepared by or under the supervision of:

Corey J. Riordan
Project Construction Controls Consultant
Dominion Energy Services, Inc.

As it pertains to interconnection viability and availability of projects, the following response to Question No. 41 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on November 15, 2024, was prepared by or under the supervision of:

Kelsi Jewell
Senior Business Development Manager
Dominion Energy Virginia

Question No. 41

Why did the Company find it necessary to impose limitations on the Plexos model regarding the total MW of storage added per year, as seen on page 55 of the IRP?

Response:

The Company puts annual build limitations into the PLEXOS model to account for a realistic build scenario taking into consideration supply chain constraints, construction capacity, interconnection viability, and availability of projects.

EXHIBIT DG-8

Company's Response to Sierra Club Discovery Request No. 1-22(b)

Virginia Electric and Power Company
Case No. PUR-2024-00184
Sierra Club
First Set

The following response to Question No. 22 of the First Set of Interrogatories and Requests for Production of Documents propounded by the Sierra Club received on October 21, 2024, was prepared by or under the supervision of:

Jarad L. Morton
Manager, Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 22

Please refer to page 53 of the 2024 IRP and identify each plant that the Company assumed would require upgrades or retrofits to comply with the following rules, along with the modeled costs and any workpapers associated with those modeled costs.

(a) 2015 Ozone National Ambient Air Quality Standards (Good Neighbor Rule);

(b) National Emission Standards for Hazardous Air Pollutants for Coal and Oil-Fired Electric Generating Units (Mercury and Air Toxics Standards or MATS);

(c) Supplemental Effluent Limitation Guidelines and Standards for Steam Electric Power Generating Point Source Category (2024 ELG);

(d) New Source Performance Standards for Greenhouse Gas Emissions from New, Modified and Reconstructed Fossil Fuel Fired Electric. Generating Units (Section 111(b)) and Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil fuel-fired Electric Generating Units (Section 111(d)).

Response:

(a) In June of 2024, the U.S. Supreme Court stayed the Good Neighbor Rule. Due to the uncertainty surrounding compliance with the rule and future compliance dates, the Company did not model compliance with the updated rule.

(b) The Company added approximately $1.5 billion in costs to the Mount Storm Power Station for compliance with the MATS rule and ELG compliance.

(c) ELG compliance was also modeled at Clover Power Station and the Virginia City Hybrid Energy Center by adding additional capital costs at each station based on compliance costs published by the EPA for the Clover Power Station. See Attachment Sierra Club Set 01-22(c) (JLM).

(d) Mount Storm Power Station, Clover Power Station, and the Virginia City Hybrid Energy Center are assumed to convert to burn 100% natural gas by 2030. Costs for these conversions are included in the overall O&M for each of these three stations and based on estimates found in supplemental documents of docket EPA-HQ-OAR-2023-0072, posted publicly on Regulations.gov. See Attachment Sierra Club Set 01-22(d) (JLM).

EXHIBIT DG-9

Company's Response to Sierra Club Discovery Request No. 1-22, Attachment 1-22(c)

SE11723

CRL_EGUs for Reg Matrix

EPA ICR ID	EIA Number	Plant Name	State	SE Unit ID	Discharge Type	Capacity (MW)	Unit Landfill Leach GPD	Retire or Fuel Conversion Year	All EGUs meet Subcategory Retirement/Refuel (2034)	Notes
9289	3954	Mount Storm	WV	SE Unit-1	Direct	570.2	67,950			0
9289	3954	Mount Storm	WV	SE Unit-2	Direct	570.2	67,950			0
9289	3954	Mount Storm	WV	SE Unit-3	Direct	522	62,206			0
4692	7213	Clover Power	VA	SE Unit-1	Direct	424	78,484			0
4692	7213	Clover Power	VA	SE Unit-2	Direct	424	78,484			0
3087	3297	Wateree Stati	SC	SE Unit-1	Direct	371.9	46,801	2028		1
3087	3297	Wateree Stati	SC	SE Unit-2	Direct	371.9	46,801	2028		1
9875	7210	Cope	SC	SE Unit-1	Direct	432.9	46,160	2030		1
864	3298	Williams Stati	SC	SE Unit-1	Direct	586.4	100,520	2032		1

SE11723

CRL_Unit_Level_SDE_Costs

Plant ID (EPA ICR)	Plant Name	SE Unit ID	Capacity (MW)	Type of Discharge	Unit CRL (GPD)	Unit Capital Cost (2023$)	Unit O&M Cost (2023$/yr)	Unit Annualized Cost (2023$)	NOTES
4692	Clover Pow	SE Unit-1	424	Direct	78,484	$17,408,356.62	1,020,341	$2,663,566.84	
4692	Clover Pow	SE Unit-2	424	Direct	78,484	$17,408,356.62	1,020,341	$2,663,566.84	
9289	Mount Stor	SE Unit-1	570.2	Direct	67,950	$13,748,929.26	870,438	$2,168,240.13	Phase A landfill has an intermittenet diverted flow that will need to be converted to ZLD. Normal operation sends the Phase A landfill leachate to the scrubber for recycling. Phase B and the retired 5-year landill discharge to the Laurel Run Mine under the mine NPDES permit. This is not accurately caputured in EPA's estimate and assumptions
9289	Mount Stor	SE Unit-2	570.2	Direct	67,950	$13,748,929.26	870,438	$2,168,240.13	
9289	Mount Stor	SE Unit-3	522	Direct	62,206	$12,586,708.30	796,859	$1,984,955.01	

NOTE: Total estimated costs are prorated across units based on MW

SE11723

Preamble_CRL Retirement Subcat Avoided Costs

EPA ICR ID		SE Unit ID	CRL Reg Opt B	Retire or Fuel Conversion Year	Smallest plant-level costs	Capital Cost Difference (2023$)	O&M Cost Difference (2023$/yr)
864	Williams	SE Unit-1	CP - retired or NG	2032	SDE	$16,175,886.62	$955,581.65
3087	Wateree	SE Unit-1	CP - retired or NG	2028	Membrane	$6,833,301.08	$1,356,438.46
3087	Wateree	SE Unit-2	CP - retired or NG	2028	Membrane	$6,833,301.08	$1,356,438.46
9875	Cope	SE Unit-1	CP - retired or NG	2030	Membrane	$7,561,991.81	$1,633,617.20

SE11776

Legacy Unit Flows_Final

ID	State	EPA ICR ID	EIA Plant Code	Plant Name	Unit Name	Dewatering Water Only (MG)	Dewatering Volume (Gallons)	Total Influent Volume (MG)	Total Volume (Gallons)	Category	Months	Dewatering Correct Months	Dewatering Flow Rate (GPD)	Total Correct Months	Total Flow Rate (GPD)	Date of Closure	Operate Past 2024
19	VA	4692	7213	Clover	North Sedimentation Basin		136481227.9		205926320.8	Legacy - Remaining Open	60	36	124640.3907	60	112836.34	Not Specified	Yes
20	VA	4692	7213	Clover	South Sedimentation Basin		136481227.9		205926320.8	Legacy - Remaining Open	61	36	124640.3907	61	110986.564	Not Specified	Yes
129	VA	7063	3796	Bremo Bluff	North Ash Pond	306.810592	306810592	306.908392	306908392	Legacy - Closing in Progress	132	36	280192.3215	84	120120.701	2034	Yes
130	VA	4679	3797	Chesterfield	Chesterfield Lower Pond	139.3513915	139351391.5	139.6773915	139677391.5	Legacy - Closing in Progress	132	36	127261.5447	84	54668.255	2034	Yes
131	VA	4679	3797	Chesterfield	Chesterfield Upper Ponc	682.0102547	682010254.7	687.5522547	687552254.7	Legacy - Closing in Progress	12	12	1868521.246	12	1883704.81	2019	No
133	VA	3804	3804	Possum Point	Surface Impoundment D	271.4778883	271477888.3	566.5078883	566507888.3	Legacy - Closing in Progress	84	36	247925.0122	84	221725.201	2030	Yes
118	SC	3087	3297	Wateree	Ash Pond 1		136481227.9		205926320.8	Legacy - Closing in Progress	180	36	124640.3907	84	80597.3858	2033	Yes

NOTE: Per SE11723, only Clover is considered in scope for Legacy leachate. Any units noted as Legacy - Closing in Progress are out of scope

SE11723

Legacy_Unit_Level_CP_Costs

EPA ICR ID	EIA Plant Co	Plant Name	SE Unit ID	Unit Total Flow	Unit CP Capital Cost	Unit CP O&M Cost	Unit 6 Year Cost	Unit Ann Cost Ye	Unit Ann Cost Year 8-20
4692	7213	Clover	SE Unit-1	111911.4521	$16,076,646.33	$1,001,627.29	$147,211.29	$2,543,684.19	$1,517,521.68
4692	7213	Clover	SE Unit-2	111911.4521	$16,076,646.33	$1,001,627.29	$147,211.29	$2,543,684.19	$1,517,521.68
					$32,153,292.66	$2,003,254.58	$294,422.58	$5,087,368.37	$3,035,043.37

EPA's list of Steam Electric EGUS as of 08/31/2023 SE11723

Population of SE EGUs_20230831

EPA ICR ID	EIA Numbe	Plant Name	State	All Majority Owners	SE Unit ID	EIA Genera	Capacity (M	Retire or Fuel Conversi	2023 (Final Rule) Update	2023 Leachate C	2024 Leachate	2020 CCR Ru	2020 CCR R	Type of NOPP
9289	3954	Mount Storm Power Station	WV	Dominion Energy	SE Unit-1	1	570.2			1	1	0		
9289	3954	Mount Storm Power Station	WV	Dominion Energy	SE Unit-2	2	570.2			1	1	0		
9289	3954	Mount Storm Power Station	WV	Dominion Energy	SE Unit-3	3	522			1	1	0		
4692	7213	Clover Power Station	VA	Old Dominion Electric Coop &	SE Unit-1	1	424			1	1	0		
4692	7213	Clover Power Station	VA	Old Dominion Electric Coop &	SE Unit-2	2	424			1	1	0		
864	3298	Williams Station	SC	SCANA Corporation	SE Unit-1	ST1	586.4	2032	Change Since Proposal	1	1	1		
9875	7210	Cope	SC	SCANA Corporation	SE Unit-1	ST1	432.9	2030		0	1	0	Not in ORCR Data Set	
3087	3297	Wateree Station	SC	SCANA Corporation	SE Unit-1	1	371.9	2028		1	1	0		2020 Rule Voluntary Incentive Program (2020 VIP)
3087	3297	Wateree Station	SC	SCANA Corporation	SE Unit-2	2	371.9	2028		1	1	0		2020 Rule Voluntary Incentive Program (2020 VIP)
4679	3797	Dominion - Chesterfield Power Sta	VA	Virginia Electric & Power Co	SE Unit-3	5	359	2023		0	0	1		
4679	3797	Dominion - Chesterfield Power Sta	VA	Virginia Electric & Power Co	SE Unit-4	6	693.9	2023		0	0	1		
8395	3287	McMeekin Station	SC	South Carolina Electric&Gas C	SE Unit-1	1	138.7	2020		0	0	0	Not in ORCR Data Set	
8395	3287	McMeekin Station	SC	South Carolina Electric&Gas C	SE Unit-2	2	138.7	2020		0	0	0	Not in ORCR Data Set	
945	3809	Yorktown Power Station	VA	Dominion Energy	SE Unit-1	3809-1; 1	175	2019		0	0	0	Not in ORCR Data Set	
945	3809	Yorktown Power Station	VA	Dominion Energy	SE Unit-2	2	182	2019		0	0	0	Not in ORCR Data Set	
4679	3797	Dominion - Chesterfield Power Sta	VA	Virginia Electric & Power Co	SE Unit-1	3	112.5	2019		0	0	1		
4679	3797	Dominion - Chesterfield Power Sta	VA	Virginia Electric & Power Co	SE Unit-2	4	187.5	2019		0	0	1		
7063	3796	Bremo Power Station	VA	Virginia Electric & Power Co	SE Unit-3	3	69	2019		0	0	1		
7063	3796	Bremo Power Station	VA	Virginia Electric & Power Co	SE Unit-4	4	185.2	2019		0	0	1		
9260	52007	Mecklenburg Power Station	VA	Dominion Energy	SE Unit-1	GEN1	69.9	2019		0	0	0	Not in ORCR Data Set	
9260	52007	Mecklenburg Power Station	VA	Dominion Energy	SE Unit-2	GEN2	69.9	2019		0	0	0	Not in ORCR Data Set	
4741	7537	North Branch Power Station	WV	Virginia Electric & Power Co	SE Unit-1	1	80	2014		0	0	0	Not in ORCR Data Set	
5981	3803	Chesapeake Energy Center	VA	Virginia Electric & Power Co	SE Unit-1	ST1	112.5	2014		0	0	1		
5981	3803	Chesapeake Energy Center	VA	Virginia Electric & Power Co	SE Unit-2	ST2	112.5	2014		0	0	1		
5981	3803	Chesapeake Energy Center	VA	Virginia Electric & Power Co	SE Unit-3	3	185.2	2014		0	0	1		
5981	3803	Chesapeake Energy Center	VA	Virginia Electric & Power Co	SE Unit-4	4	239.3	2014		0	0	1		
876	10771	Hopewell Power Station	VA	Dominion Energy	SE Unit-1	1	71.1	2013		0	0	0	Not in ORCR Data Set	
4671	10774	Southampton Power Station	VA	Virginia Electric & Power Co	SE Unit-1	1	71.1	2013		0	0	0	Not in ORCR Data Set	
9374	10773	Altavista Power Station	VA	Dominion Energy	SE Unit-1	1	71.1	2013		0	0	0	Not in ORCR Data Set	
1761	3280	Canadys Station	SC	SCANA Corporation	SE Unit-2	2	125.2	2013		0	0	0	Not in ORCR Data Set	
1761	3280	Canadys Station	SC	SCANA Corporation	SE Unit-3	3	220.9	2013		0	0	0	Not in ORCR Data Set	
1761	3280	Canadys Station	SC	SCANA Corporation	SE Unit-1	1	125.2	2012		0	0	0	Not in ORCR Data Set	
9861	3295	Urquhart Station	SC	SCANA Corporation	SE Unit-3	3	105.7	2012		0	0	0	Not in ORCR Data Set	

Units Not listed:

Possum 1/2 coal and shut down, Possum 3/4 were coal converted to gas and shut down , Possum 5 was oil only and shut down, and Unit 6 is combined cycle for oil or gas

VCHEC is circulating fluidized bed boiler, intitally operated as ZLD

Chesterfield Units 7 and 8 are combined cycle

McMeekin Gas Fired Steam

Urquhart 1/2/3/4 and CC

EXHIBIT DG-10

Company's Response to Commission Staff Discovery Request No. 7-154(k)

Virginia Electric and Power Company
Case No. PUR-2024-00184
Virginia State Corporation Commission Staff
Seventh Set

The following response to Question No. 154(a) through (j) and (l) of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on January 2, 2025, was prepared by or under the supervision of:

Jarad L. Morton
Manager, Integrated Strategic Planning
Dominion Energy Services, Inc.

The following response to Question No. 154(e) and (k) of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on January 2, 2025, was prepared by or under the supervision of:

Michael S. Oberleitner
Fuel Commodity Specialist
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 154 of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on January 2, 2025, was prepared by or under the supervision of:

Nicole M. Allaband
McGuireWoods LLP

Question No. 154

Please refer to the Company's response to Staff Interrogatory No. 3-86.

(a) When modeling the conversion of the three coal units to burn natural gas, was each unit still available for the model to select for dispatch during the period during which the conversion would take place?

(b) Please provide a narrative discussion of how the Company accounts for the downtime associated with making these conversions, what assumptions the Company makes about these unit's ability to run continuously throughout the conversion process, and how to account for other energy or capacity resources that would be needed to cover any lost energy and capacity of these three units while they underwent conversion.

(c) Please provide a narrative discussion of how, in the modeling, the Company accounted for each unit's characteristics during the time from when the unit started its conversion until completion. Please include in that discussion any modifications to the capacity and energy production characteristics, or changes in availability, that may have been modified to account for interruptions related to the work necessary to convert the units to burn natural gas.

(d) Do the total costs of converting the units include the cost of providing for an alternative fuel source? If so, what secondary fuel source was assumed? If not, why?

(e) Do the total costs of converting the units include the costs of the new greenfield pipeline laterals?

(f) Do the total costs of converting the units include any lost energy or capacity resulting from the units not being available while the units are being converted to burn natural gas?

(g) Please provide a narrative explanation why the generation from coal is higher on average over the period of 2027 through 2029 in the VCEA with EPA Portfolio as compared to the VCEA without EPA Portfolio.

(h) Once the units are converted to burn natural gas, will these units be considered new natural gas units for the purpose of the new EPA rules? Please provide a narrative discussion of the Company's understanding or reasoning as to why or why not.

(i) Does the Company anticipate, and does the Company's modeling reflect, all three units undergoing the necessary conversions simultaneously and the simultaneous construction of the greenfield pipeline laterals?

(j) Please provide a narrative discussion of what the consequences would be if the conversion took longer than 3 years.

(k) Please refer to sub-part (h) of the Company's response. What does the Company mean when it says, "fully subscribed"?

(l) Please refer to sub-part (i) of the Company's response What's the timeline from (i) Dominion determining that it must convert the units, to (ii) the units being fully converted to burn natural gas, to (iii) the greenfield pipelines being in place to deliver fuel? At what point in this process would the Company expect to have the secondary fuel source in place for each of the units?

Response:

The Company objects to this request as not relevant or reasonably calculated to lead to the production of admissible evidence in this proceeding as the Company is not seeking approval of any particular resource in this proceeding. The Company also objects to this request because it calls for a speculative response that would depend on many case-specific factors at the time of filing a request for approval of a resource. Notwithstanding and subject to these objections, the

Company provides the following response.

(a) Yes. As explained in Section 5.1 of the 2024 IRP, the Company needed to make certain compliance assumptions related to the new environmental regulations described in that section, for the 2024 IRP modeling. The Company chose to model compliance with Section 111(d) by converting the Company's three remaining coal stations to burn natural gas by January 1, 2030, using costs published by the EPA. Given that the final rule under Section 111(d) was not published until May 9, 2024, and the 2024 IRP was due to be filed on October 15, 2024, the Company has not had time to fully evaluate how each station might comply with Section 111(d) along with other recently finalized environmental regulations. Without time to conduct further analysis, the modeling assumptions used for converting the existing coal stations to natural gas were high-level and limited to those costs published by EPA. It is important to note that the Company has not finally decided how it will choose to comply with Section 111(d) and is not obligated to do so until May of 2026. It is also important to note that the Company is not seeking Commission approval for the gas conversion of its remaining coal stations in this filing. The Company is continuing to evaluate options for compliance, as well as the costs and timeline of those options, and will continue to refine its assumptions in future IRP filings.

(b) See the Company's response to subpart (a)

(c) See the Company's response to subpart (a)

(d) See the Company's responses to subpart (a) and Staff Set 03-86(f).

(e) No. See the Company's responses to subpart (a), as well as Staff Set 03-86(g) and United Set 02-22(d).

(f) No. See the Company's response to subpart (a)

(g) The capacity factors of coal units in the VCEA with EPA and VCEA without EPA Portfolios are slightly different due to the energy and commodity forecast differences between the two ICF forecasts. This difference is small and averages to less than 0.3% from 2027-2029.

(h) The Company objects to this request because it calls for a legal conclusion. Notwithstanding and subject to this objection, the Company provides the following response.

    No. If a unit converts from coal to natural gas, the unit can operate as a "natural gas steam generating unit" under EPA's Section 111(d) rule. Natural gas steam generating units under the Section 111(d) rules do not have to retire, those units must meet applicable emission limitations based on the unit's capacity factor upon startup. All coal operations would need to cease by January 1, 2030.

(i) The Company's analysis did not include the timing of the conversions. The analysis and modeling incorporated the costs of conversion. See the Company's response to subpart (a).

(j) See the Company's response to subpart (a). The Company cannot speculate at this time as to what, if any, consequences there would be, or whether there would be exceptions to the rule, if possible gas conversions were to take longer than 3 years.

(k) The term "fully subscribed," as it pertains to natural gas pipelines, means there is no available, unsubscribed, firm transportation on the pipeline.

(l) See the Company's response to subpart (a).

EXHIBIT DG-11

Company's Response to Commission Staff Discovery Request No. 3-100

<u>Virginia Electric and Power Company</u>
<u>Case No. PUR-2024-00184</u>
<u>Virginia State Corporation Commission Staff</u>
<u>Third Set</u>

The following response to Question No. 100 of the Third Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on December 10, 2024, was prepared by or under the supervision of:

Michael S. Oberleitner
Fuel Commodity Specialist
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 100 of the Third Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on December 10, 2024, was prepared by or under the supervision of:

Nicole M. Allaband
McGuireWoods LLP

Question No. 100

Please refer the IRP at Section 3.8, "The Five-Year Reliability Plan."

Has the Company studied, or is the Company planning on studying, the reliability of the natural gas transportation systems used to supply fuel to the Company's fleet of gas-fired generating stations? If not, why?

a. Each of the Company's four IRP Portfolios contemplate building approximately 6,000 MW of natural gas-fired generation. Has the Company analyzed whether sufficient natural gas transportation is available to the Company to support the fuel needs of these units? If not, why?

b. Has the Company determined whether additional greenfield natural gas transportation infrastructure would be need in order to support the increased demand for fuel to the new facilities that the Company has modeled? If not, why?

c. Please also reference https://www.deq.virginia.gov/topics-of- interest/dominion-chesterfield-energy-reliability-center-project. Has the Company determined how the fuel for the 944 MW natural gas-fired facility identified in each Portfolio will be transported and delivered? Please identify the interstate pipeline, or pipelines, that will support this station, as well as a narrative explanation of the contracts for gas transportation that the Company has sought or plans on seeking.

d. How does the Company view the reliability of the interstate gas transportation system when it considers its overall system reliability?

e. Please indicate the expected natural gas consumption required by each of the Company's four Portfolios p [*sic*] on a per-year basis for any new generation resources, expressed in dekatherms per year.

Response:

a. through c. The Company objects to this request as not relevant or reasonably calculated to lead to the production of admissible evidence in this proceeding as the IRP is not a request for a certificate of public convenience and necessity, nor a request for cost approval of any particular resource. If and when the Company seeks approval of any new resource, it will file an application with all the necessary filing requirements, including any fuel supply studies, as appropriate. Notwithstanding and subject to this objection, the Company provides the following response.

   The Company is not leading a formal "study," but is heavily engaged with the interstate natural gas pipeline system serving its natural gas generation fleet. In addition to daily communications with the four interstate pipelines directly serving the Company's power stations, the Company is involved in federal regulatory proceedings (*e.g.*, interstate pipeline FERC Section 4 rate filings), various federal and regional forums in which interstate pipelines participate (*e.g.*, PJM, NERC, NAESB), and seasonal pipeline operations meetings. The Company will also contact pipelines if and when additional delivery/storage services are contemplated. Consequently, the Company's daily involvement through various operational and regulatory aspects provides a well-founded awareness of transportation delivery reliability on these pipelines, and which conditions and/or events may materially affect reliable deliveries.

d. The Company views the interstate pipeline transportation system, serving its natural gas fired generation fleet as reliable. The Company is also aware of operational constraints and ongoing gas electric coordination issues that can affect pipeline transportation, flexibility, and/or fuel delivery on the interstate gas transportation system. As noted above, the Company is working with various regional and federal entities to address some of the issues affecting overall system reliability.

e. See the Company's response to Attachment Sierra Club Set 01-02 (CONF_ES), PLEXOS Outputs (JLM) CONF. In each Portfolio output file, the fuel offtake field provides fuel consumption by plant, by year.

EXHIBIT DG-12

Company's Response to Clean Virginia Discovery Request No. 2-2

Virginia Electric and Power Company
Case No. PUR-2024-00184
Clean Virginia
Second Set

The following response to Question No. 2 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Clean Virginia received on December 6, 2024, was prepared by or under the supervision of:

Harrison S. Potter
Manager – ET Area Planning
Dominion Energy Virginia

M. Robert Hines
Director – Finance
Dominion Energy Virginia

Question No. 2

Reference the Company's SCC Directed 2024 IRP Supplement, in which the Company provides a list of planned transmission projects during the planning period and the associated costs (Supplemental Appendix 2C-2).

a. Please clarify whether these cost estimates reflect overnight costs.

b. Please explain how the total costs of the projects listed in Supplemental Appendix 2C-2 are related to the NPV of Transmission costs ($22.4 billion) shown in Table 5.2.2 of the Company's 2024 Integrated Resource Plan.

Response:

a. Costs provided are estimates that include labor, materials, engineering, support, and Allowable Funds Used During Construction.

b. The list of Planned Transmission Projects in Appendix 2C-2 represents the baseline upgrade and supplemental projects within the DOM Zone that have been incorporated into PJM's Regional Transmission Expansion Plan ("RTEP") base case, also referred to as the planning model. Details regarding the RTEP process can be found in PJM's Manual 14B: PJM Region Transmission Planning Process (https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf).

   The primary difference is Table 5.2.2 represents the NPV of the high level, estimated costs for the work required to ensure transmission grid reliability for the Planning Period (2025 through 2039). This is inclusive of the costs of the transmission projects included in Appendix 2C-2.

EXHIBIT DG-13

Company's Response to Commission Staff Discovery Request No. 5-134(e)

Virginia Electric and Power Company
Case No. PUR-2024-00184
Virginia State Corporation Commission Staff
Fifth Set

The following response to Question No. 134 of the Fifth Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on December 17, 2024, was prepared by or under the supervision of:

Rob Hines
Director – Dominion Energy Virginia Finance
Virginia Electric and Power Company

Question No. 134

Please refer to Table 5.2.2: NPV Results for Primary Portfolios, on page 66 of the IRP.

(a) Please provide a narrative description of how the Company develops the transmission cost NPVs.

(b) Are these costs associated only with the projects listed in Appendix 2C-2?

(c) Are the Appendix 2C-2 projects incorporated only in part?

(d) What level of specificity do these costs represent? For example, are there costs included for specific transmission interconnections or upgrades that the system will need to support the SMR modeled in 2037 in the VCEA with EPA Build Plan Summary?

(e) If all or part of these costs are associated with "generic" transmission projects (defined as having no particularly distinctive quality or application; or, relating to or characteristic of a whole group or class), how does the Company use this information to inform its real-world system planning?

Response:

(a) The electric transmission costs are estimated throughout the IRP Planning Period (2025-2039) for expected work required to ensure transmission grid reliability. A net present value is then calculated consistent with other net present value calculations in the 2024 IRP filing.

(b) See the Company's response to Clean Virginia Set 02-02.

(c) See the Company's response to subpart (b).

(d) The transmission costs represent the costs associated with transmission growth and reliability included in the Planning Period with high level annual estimates, not developer interconnection costs or associated network upgrades.

(e) The Company includes known costs in the near-term and includes generic costs for more long-term planning. The Company will continue to evaluate and refine its more long-term assumptions and costs in future IRPs.

CERTIFICATE OF SERVICE

I certify that on February 28, 2025, I sent the foregoing by electronic mail to:

William H. Chambliss
Arlen Bolstad
Kiva Bland Pierce
Mike Zielinski
State Corporation Commission
Office of General Counsel
Post Office Box 1197
Richmond, Virginia 23218

Paul E. Pfeffer
Lisa R. Crabtree
Dominion Energy Services
120 Tredegar Street
Richmond, Virginia 23219

C. Meade Browder Jr.
Office of the Attorney General
Division of Consumer Counsel
202 North Ninth Street — Eighth Floor
Richmond, Virginia 23219

Sarah B. Nielsen
McGuireWoods
1301 Gervais Street, Suite No. 1310
Columbia, South Carolina 29201

Cody T. Murphey
John O'Malley
Cassidy G. Galindo
Williams Mullen
200 South Tenth Street, Suite No. 1600
Richmond, Virginia 23219

Carrie H. Grundmann
Hikmat N. Al-Chami
Spilman Thomas & Battle
110 Oakwood Street, Suite No. 500
Winston-Salem, North Carolina 27103

Nathan Benforado
Rachel James
Josephus Allmond
E. Grayson Holmes
Emma Clancy
Southern Environmental Law Center
120 Garret Street, Suite No. 400
Charlottesville, Virginia 22902

Vishwa B. Link
Nicole M. Allaband
McGuireWoods
800 East Canal Street
Richmond, Virginia 23219-3916

Gregory Habeeb
Jasdeep Khaira
Gentry Locke
919 East Main Street, Suite No. 1130
Richmond, Virginia 23219

William T. Reisinger
ReisingerGooch
1108 East Main Street, Suite No. 1102
Richmond, Virginia 23219

Cliona Mary Robb
Michael J. Quinan
Catherine Chapman
Thompson McMullan
100 Shockoe Slip – Third Floor
Richmond, Virginia 23219

Timothy G. McCormick
Christian F. Tucker
Christian & Barton
901 East Cary Street, Suite No. 1800
Richmond, Virginia 23219-3095

Angelina S. Lee
DEPARTMENT OF THE NAVY
6506 Hampton Boulevard
Norfolk, Virginia 23508-1278

Brian R. Greene
Eric J. Wallace
Clarice M. Gardner
Alexis Laundry
GREENEHURLOCKER
4908 Monument Avenue – Second Floor
Richmond, Virginia 23230

Bryan P. MacAvoy
ALEXANDRIA CITY ATTORNEY'S OFFICE
301 King Street – Suite 1300
Alexandria, Virginia 22314

William C. Cleveland
LIGHTHOUSE POLICY & LAW
240 West Main Street – Suite 100
Charlottesville, Virginia 22902

Andrew R. McRoberts
Adam B. Winston
SANDS ANDERSON
919 East Main Street – Suite 2300
Post Office Box 1998
Richmond, Virginia 23218-1998

Evan Dimond Johns
(Virginia State Bar No. 89285)