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Application of Virginia Electric and Power Company for approval of a rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia
Case No. PUR-2025-00076

Dear Mr. Logan:

Enclosed for electronic filing in the above-captioned proceeding, please find the *Application of Virginia Electric and Power Company for approval of a rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia*.

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

Highest regards,

/s/ Jontille D. Ray

Jontille D. Ray

Enc.

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Application, Direct Testimony, Exhibits and Schedules of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

For approval of a rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia

Case No. PUR-2025-00076

Filed: May 1, 2025

Volume 1 of 3

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY For approval of a rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia	))))))	Case No. PUR-2025-00076

APPLICATION

Virginia Electric and Power Company (the "Company"), by counsel, pursuant to § 56-585.1 A 4 ("Subsection A 4") of the Code of Virginia ("Va. Code") and 20 VAC 5-204-5, 20 VAC 5-204-10, 20 VAC 5-204-60, and 20 VAC 5-204-90 of the Rules Governing Utility Rate Applications and Annual Informational Filings for Investor-Owned Electric Utilities, 20 VAC 5-204-5, *et seq.* (the "Rate Case Rules"), respectfully files its application with the State Corporation Commission of Virginia (the "Commission") for approval of a revised increment/decrement rate adjustment clause ("RAC") designated as Rider T1, for an adjustment to the Company's recovery of costs under Subsection A 4, described in detail below and currently being recovered through a combination of the Subsection A 4 component of base rates and the current Rider T1 (the "Application").

Approval of this revised Rider T1 will assure the timely and current recovery of the Company's Subsection A 4 revenue requirement for the rate year September 1, 2025 through August 31, 2026 ("Rate Year"), including (i) costs charged to the Company by PJM Interconnection, L.L.C. ("PJM") for transmission services provided to the Company by PJM, as determined under applicable rates, terms, and conditions approved by the Federal Energy Regulatory Commission ("FERC"); and (ii) costs charged to the Company by PJM associated with demand response programs approved by FERC and administered by PJM. In support of its Application, the Company respectfully states the following:

I. GENERAL INFORMATION

1. The Company is a public service corporation organized under the laws of the Commonwealth of Virginia furnishing electric service to the public within its certificated service territory. The Company also supplies electric service to nonjurisdictional customers in Virginia and to the public in portions of North Carolina. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation. The Company is also a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the FERC. The Company is an operating subsidiary of Dominion Energy, Inc. The Company's name and address is:

Virginia Electric and Power Company
600 East Canal Street
Richmond, Virginia 23219

2. The addresses and telephone numbers of the attorneys for the Company are:

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II. BACKGROUND, SUMMARY AND BASIS FOR SUBSECTION A 4 RAC

3. Subsection A 4, adopted during the 2007 Session of the Virginia General Assembly as part of what is now known as the Virginia Electric Utility Regulation Act (the "Act"), provides in relevant part that the following costs incurred by an investor-owned incumbent electric utility,[1] such as the Company, "shall be deemed reasonable and prudent": "(i) costs for transmission services provided to the utility by the regional transmission entity of which the utility is a member, as determined under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission" ("A 4(i) Costs"); and "(ii) costs charged to the utility that are associated with demand response programs approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member" ("A 4(ii) Costs"). Subsection A 4 provides further that "[u]pon petition of a utility at any time after the expiration or termination of capped rates, but not more than once in any 12-month period, the Commission shall approve a rate adjustment clause under which such costs, including, without limitation, costs for transmission service; charges for new and existing transmission facilities, …; administrative charges; and ancillary service charges designed to recover transmission costs, shall be recovered on a timely and current basis from customers." Finally, Subsection A 4 states that "[r]etail rates to recover these costs shall be designed using the appropriate billing determinants in the retail rate schedules."

[1] The term "incumbent electric utility" is defined to mean "each electric utility in the Commonwealth that, prior to July 1, 1999, supplied electric energy to retail customers located in an exclusive service territory established by the Commission." Va. Code § 56-576.

4. Effective May 1, 2005, the Company integrated into PJM, a regional transmission entity that has been approved as a regional transmission organization ("RTO") by FERC, at which time PJM assumed operational control of the Company's electric transmission facilities, and the Company gained direct access to the PJM capacity and energy markets. Accordingly, PJM is "the regional transmission entity of which the [Company] is a member" for the purposes of Subsection A 4. As an integrated electric utility member of PJM, the Company obtains transmission service from PJM and pays PJM charges for such service at the rates contained in PJM's Open Access Transmission Tariff ("PJM OATT") approved by FERC. These charges constitute A 4(i) Costs and include:

A. Network Integration Transmission Service ("NITS") charges in accordance with the PJM OATT, Attachment H-16, Annual Transmission Charges – Virginia Electric and Power Company, based on PJM rates for calendar years 2024 and 2025;

B. Annual PJM charges under the PJM OATT, Schedule 12, Transmission Enhancement Charges (which are based upon the latest data available through PJM) for net transmission service enhancement charges/credits;

C. PJM administrative charges calculated under the PJM OATT, Schedule 9, Administrative Services; and

D. PJM charges under the PJM OATT, Schedule 1A for Scheduling, System Control, and Dispatch Service ancillary services.[2]

5. The Company also pays PJM charges for the costs of PJM demand response programs – *i.e.*, the Economic Load Response Program and the Emergency and Pre-Emergency

[2] The Company currently recovers these costs through its NITS rate and, therefore, does not have a separately stated rate in the PJM tariff for these ancillary services.

Load Response Program – determined in accordance with Section 3.3A of Attachment K of the PJM OATT, the last section of Attachment K (labeled Emergency and Pre-Emergency Load Response Program). Both are demand response programs approved by FERC and administered by PJM and, as such, constitute A 4(ii) Costs. Accordingly, the Company has incurred, and will continue to incur, these A 4(i) Costs and A 4(ii) Costs (collectively, the "Subsection A 4 Costs"), which are deemed by Subsection A 4 to be reasonable and prudent.

6. The Company made its initial filing for Commission approval of a Subsection A 4 RAC, designated Rider T, on March 31, 2009, in Case No. PUE-2009-00018, which the Commission approved with certain modifications on June 29, 2009.[3] Since this initial proceeding, the Company has annually petitioned the Commission to update Rider T (re-designated Rider T1 in the 2012 proceeding, Case No. PUE-2012-00052).

7. In last year's Rider T1 proceeding, Case No. PUR-2024-00071 ("2024 Rider T1 Case"), the Company made its 15th revised Subsection A 4 RAC filing seeking approval of a total revenue requirement of $1,169,592,808, representing a $249,440,612 increase in recovery from the projected revenues associated with the then-effective Subsection A 4 component of base rates determined for the 2024-2025 rate year and the then-effective Rider T1. The Company sought approval of a revised increment/decrement Rider T1 in the amount of $638,238,346, as well as various rate design and tariff revisions. The Commission Staff ("Staff") supported the Company's proposed revenue requirement and the amounts to be recovered through the Subsection A 4 component of base rates and Rider T1. The Commission approved a total Subsection A 4 revenue requirement of $1,169,592,808 for recovery through

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[3] *Application of Virginia Electric and Power Company For approval of rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia*, Case No. PUE-2009-00018, Final Order, 2009 S.C.C. Ann. Rept. 422-26 (June 29, 2009).

base rates and the Company's updated Rider T1 for implementation in rates during the 2024-2025 rate year. Additionally, the Commission approved the Company's proposed cost allocation and rate design revisions.[4]

8. Consistent with the methodology approved in the 2024 Rider T1 Case, in order to recover its Subsection A 4 Costs on a timely and current basis from customers, as required by Subsection A 4, the Company seeks Commission approval in this Application of a Subsection A 4 revenue requirement for the Rate Year to be recovered through a combination of base rates and a revised Rider T1 designed to recover the increment/decrement between the revenues produced from the Subsection A 4 component of base rates and the new revenue requirement developed from the Company's Subsection A 4 costs for the Rate Year.

9. For purposes of developing the revenue requirement for consideration in this proceeding, the Company has assumed an effective date of September 1, 2025. The Company proposes Rider T1 be effective for usage during the Rate Year, consistent with the rate year approved in the previous Rider T/T1 cases. The Company forecasts collection of $560,916,458 through the Subsection A 4 component of base rates and proposes a $782,419,277 revenue requirement through Rider T1. Thus, the net total Subsection A 4 revenue requirement is $1,343,335,735.

10. As discussed by Company Witness William J. Caffall, the Company requests for billing purposes, a rate effective date for usage on or after September 1, 2025. However, if the Commission issues an order that is not at least fifteen (15) days prior to this proposed effective date, the Company respectfully requests, for billing purposes, a rate effective date for usage on

[4] *See Application of Virginia Electric and Power Company For approval of rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia*, Case No. PUR-2024-00071, Final Order (July 26, 2024).

and after the first day of the month which is at least fifteen (15) days following the date of any Commission order approving Rider T1.

III. DIRECT TESTIMONY AND SUPPORTING EVIDENCE

11. In support of its Application, the Company hereby files the direct testimony of three witnesses.

A. David M. Wilkinson, Manager – Regulation in the Regulatory Accounting Department for the Company, will present the Company's revenue requirement for recovery of Subsection A 4 Costs for the Rate Year, including the increment/decrement to be recovered through Rider T1; the formula mechanism and protocol for developing this revenue requirement for appropriate recovery of Subsection A 4 Costs; the update of certain Subsection A 4 Costs for known changes during the Update Period of January 1, 2025 through August 31, 2025; and the annual deferral and True-up mechanisms – all to assure timely and current recovery of Subsection A 4 Costs reflected in this revenue requirement, and to ensure that customers will be charged only actual costs incurred, all consistent with the Commission's previous Rider T/T1 Orders.

B. Michael J. Batta, Senior Strategic Advisor in the FERC Policy Group, will provide an overview and description of PJM and the specific FERC-approved Subsection A 4 Costs reflected in the revenue requirement presented by Mr. Wilkinson.

C. William J. Caffall, Regulatory Analyst III for the Company, will present the Company's proposed methodology for the design and calculation of retail rates for recovery of such Subsection A 4 Costs, including the Rider T1 rates to be approved in this proceeding, using the appropriate billing determinants as directed by Subsection A 4.

IV. SUPPORTING FILING SCHEDULE 46

12. Rule 60 of the Rate Case Rules, 20 VAC 5-204-60, provides that an application filed pursuant to Subsection A 4 "shall include Schedule 46 as identified and described in 20 VAC 5-204-90, which shall be submitted with the utility's direct testimony." Rule 60 additionally requires the filing of Schedules 3, 4, 5, and 8 for those "applications requiring an overall cost of capital." As there is no cost of capital directly in Rider T1, Schedules 3, 4, 5, and 8 are not required to be filed with this Application.

13. Filing Schedule 46 is divided into three sections:

A. Filing Schedule 46A, sponsored by Company Witness Wilkinson, provides: a schedule of all projected costs by type of cost and year associated with Subsection A 4 Costs for the Rate Year, including the increment/decrement for this proceeding, for which the Company is seeking Commission approval in this proceeding; and the annual revenue requirement by year on a total company and Virginia jurisdictional basis, including all supporting calculations and assumptions.[5]

B. Filing Schedule 46B, sponsored by Company Witness Batta, provides an index to FERC rulings approving the wholesale transmission formula, rate, or cost for which the Company is now seeking recovery approval under Subsection A 4, including the docket/case number(s) of each such ruling.

C. Filing Schedule 46C, sponsored by Company Witness Caffall, provides detailed information relative to the Company's methodology for allocating the Rider T1 increment/decrement among rate classes, as well as the design of the class rates, and also the annual revenue requirement over the duration of the proposed RAC allocated by

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[5] As Rider T1 is filed on an annual basis with no duration of the RAC, the Company has provided the annual revenue requirement for the next 10 years (2025-2034).

class.

V. COMPLIANCE WITH RATE CASE RULE 10

14. The Company's 2025 Rider T1 Application complies with the requirements contained in Rule 10 of the Rate Case Rules, 20 VAC 5-204-10 ("Rule 10"). In accordance with Rule 10 A, the Company filed with the Commission on February 27, 2025, a notice of intent to file this Application under Subsection A 4, and served copies upon the persons addressed in Rule 10 J (1). A complete copy of this Application has been served upon the Division of Consumer Counsel of the Office of the Attorney General, in conformity with Rule 10 J (3). Also included with and following this Application, pursuant to Rule 10, is a table of contents of this filing, including exhibits and schedules.

WHEREFORE, the Company requests the Commission to: (i) schedule this matter for hearing; (ii) approve the proposed revised Rider T1 for an adjustment to the recovery of Subsection A 4 Costs; and (iii) grant the Company such further relief as may be necessary or appropriate.

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By: *<u>/s/ Jontille D. Ray</u>*
Counsel

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Counsel for Virginia Electric and Power Company

May 1, 2025

Virginia Electric and Power Company
Subsection A 4 Rate Adjustment Clause
Case No. PUR-2025-00076

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<u>Witness Direct Testimony Summary</u>

<u>Witness</u>: David M. Wilkinson
<u>Title</u>: Manager – Regulation in the Regulatory Group
<u>Summary</u>:

Company Witness David M. Wilkinson provides the calculation of the revenue requirement associated with the Subsection A 4 rate adjustment clause, Rider T1, as well as supporting financial information and accounting procedures and internal controls provided in Filing Schedule 46A.

The following are key points of Mr. Wilkinson's direct testimony:

- Dominion Energy Virginia's Subsection A 4 revenue requirement in this proceeding is based upon: (1) costs for transmission services provided to the Company by PJM, the regional transmission entity of which the Company is a member, according to applicable rates, terms, and conditions approved by the FERC; and (2) costs charged to the Company associated with demand response programs approved by the FERC and administered by PJM.

- The total Subsection A 4 revenue requirement is $1,343,335,735 for the Rate Year September 1, 2025 – August 31, 2026.

- The total revenue requirement is $79,675,299 more than the revenues projected to be recovered during the Rate Year by the combination of the base rate component of Subsection A 4 and the Rider T1 rates currently in effect.

- The total revenue requirement is $173,742,927 more than the total revenue requirement approved for recovery in the 2024 Rider T1 case.

- The higher total revenue requirement is primarily due to significant increases in the cost of net investment in plant included in the Network Integration Transmission Service ("NITS") charges billed by PJM, a higher true-up adjustment under-recovery, and a higher update adjustment.

DIRECT TESTIMONY
OF
DAVID M. WILKINSON
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2025-00076

I. INTRODUCTION

Q. Please state your name, position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), and business address.

A. My name is David M. Wilkinson. I am a Manager – Regulation in the Regulatory Accounting department for the Company. My business address is 120 Tredegar Street, Richmond, Virginia 23219. A statement of my background and qualifications is attached as Appendix A.

Q. Please describe your areas of responsibility with the Company.

A. I am responsible for the development of revenue requirement analyses and calculations used for rate setting purposes in rate proceedings before the State Corporation Commission of Virginia (the "Commission") and in other jurisdictions.

Q. Will you be introducing any exhibits with your testimony?

A. Yes. Company Exhibit No. __, DMW, consisting of Schedule 1 (consisting of Formula Schedules 1 through 10) and Schedule 2 (consisting of Formula Schedule 11), was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief. I am also sponsoring Filing Schedule 46A, Statements 1 through 13, included with the Company's Application pursuant to the Commission's

Rules Governing Utility Rate Applications and Annual Informational Filings of Investor-Owned Electric Utilities, 20 VAC 5-204-5, *et seq.*

Q. Will Dominion Energy Virginia present any other witnesses in this proceeding?

A. Yes. Company Witness Michael J. Batta will discuss PJM Interconnection, L.L.C. ("PJM") and the Company's activities as a member of PJM. Additionally, Mr. Batta will describe the nature of the charges and credits billed to the Company by PJM, as well as the rates and tariffs approved by the Federal Energy Regulatory Commission ("FERC") used to develop the costs under the Virginia Electric Utility Regulation Act (the "Act"), § 56-585.1 A 4 ("A 4" or "Subsection A 4") of the Code of Virginia ("Va. Code"), included for recovery under Subsection A 4 in this case.

Company Witness William J. Caffall will testify regarding the allocation of the rate adjustment clause ("RAC"), designated Rider T1, the revenue requirement among the customer classes, and the rate design for recovering the revenue requirement through retail rates.

Q. Please describe the purpose of your testimony in this proceeding.

A. My testimony will present the total revenue requirement of $1,343,335,735 that the Company is seeking to recover through a combination of base rates and Rider T1 from Virginia jurisdictional retail customers under Subsection A 4, for the twelve-month rate year beginning September 1, 2025 and ending August 31, 2026 (the "Rate Year"). This total revenue requirement includes an increment Rider T1 of $782,419,277, which will be discussed later in my testimony. The requested total revenue requirement of $1,343,335,735 represents an increase of $79,675,299 over the revenues projected to be produced during the Rate Year by the combination of the base rate component of Subsection A 4 (the Company's former Rider T) and the Rider T1 rates currently in effect.

Q. How does the total revenue requirement requested in this Application differ from that approved for recovery in last year's Rider T1 proceeding?

A. The requested total revenue requirement in this Application of $1,343,335,735 represents an increase of $173,742,927 from the total revenue requirement approved for recovery in Case No. PUR-2024-00071 (the "2024 Rider T1 Case"). A detailed description of the reasons for the increase is provided in my conclusion, beginning on page 36 of my testimony.

In summary, the increase in the total revenue requirement requested in this Application is primarily due to significant increases in the cost of net investment in plant included in the Network Integration Transmission Service ("NITS") charges billed by PJM, a higher true-up adjustment under-recovery, and a higher update adjustment. These items are slightly offset by higher net transmission enhancement credits. All the costs in this Application are based on FERC-approved tariffs. The increased charges associated with plant investment included in the NITS rate are enhanced by transmission enhancement charges ("Transmission Enhancement Charges"), which represent charges from PJM for transmission projects from members of PJM for which the responsibility of cost is shared and which are higher than the prior year, offset by transmission enhancement credits ("Transmission Enhancement Credits"), which represent amounts for Dominion Energy Virginia transmission projects for which there is shared cost responsibility with other PJM members. The Transmission Enhancement credits are also a higher amount than the prior year, which decreases the total revenue requirement. The increased charges for net investment in plant are found in the projected Subsection A 4 cost of service (as the net of the NITS charges on Schedule 1, Formula Schedule 2, Page 1, Line 1 and the net Transmission Enhancement Charges/Credits on Schedule 1, Formula Schedule 2, Page 1, Lines 25 and 27) and a component of the Update Period adjustment (discussed later in this testimony) on my Schedule 1, Formula Schedule 10, Page 1, Line 15. A continuing item in the net transmission enhancement costs this year is the Dominion Energy Virginia settlement for FERC Docket No. EL05-121-009 (the "East/West Settlement"). See the pre-filed direct testimony of Company Witness Batta for a description of this settlement.

Q. What is the primary reason for the increase in net investment in the transmission plant?

A. As discussed in the pre-filed direct testimony of Company Witness Batta, the Company has projected an increase in investment in transmission plant from December 31, 2024, to December 31, 2025, of nearly $2.2 billion. This amount includes projects that are deemed to be either PJM Regional Transmission Expansion Plan ("RTEP") baseline reliability projects or other reliability projects. The Company is contractually obligated through the PJM Consolidated Transmission Owners Agreement to construct any reliability upgrade assigned to the Company through the RTEP process by PJM. Also, FERC-approved and North American Electric Reliability Corporation ("NERC")-enforced reliability standards require that transmission owners ("TOs") remedy any potential reliability violation or face penalties in excess of $1 million per day per violation if found to be in noncompliance. The Company is required to maintain the reliability of the transmission system.

Q. Would you provide an overview of the recovery mechanism that the Company is requesting in this proceeding?

A. Consistent with the methodology approved in previous cases, the Company is requesting approval of a revised increment/decrement RAC, Rider T1, under Subsection A 4 to adjust the combination of the existing Subsection A 4 component of base rates and the currently existing Rider T1. The Rider T1 presented in this case is designed to recover the increment/decrement between the revenues produced from the current Subsection A 4 component of base rates and the new revenue requirement developed from the Company's Subsection A 4 costs for the Rate Year presented in this Application. The Company will continue to identify and track separately Subsection A 4 costs and the revenues derived from both the Subsection A 4 component of base rates and Rider T1, thus maintaining the dollar-for-dollar recovery of these costs and the associated deferral accounting consistent with Commission approval in prior Subsection A 4 cases. The Company proposes the approval of this updated Rider T1 to recover the increment/decrement of total Subsection A 4 costs relative to the Subsection A 4 component of base rates.

Q. Please describe the Company's proposed mechanism for determining the revenue requirement associated with the updated Rider T1.

A. As presented in my Schedule 2, Formula Schedule 11, the revenue requirement proposed to be recovered through the revised Rider T1 in this proceeding is $782,419,277. This amount is determined by comparing: (1) the Company's total proposed revenue requirement of $1,343,335,735 for recovery of Subsection A 4 costs during the Rate Year; and (2) the $560,916,458 of revenue projected to be produced by the current

Subsection A 4 component of base rates during the Rate Year. I will discuss the revenue requirement calculations in detail in Section III of my testimony.

Q. Are the Subsection A 4 costs that the Company proposes to recover in this case consistent with those approved by the Commission in the Company's previous Rider T and Rider T1 cases?

A. Yes, they are consistent with previous cases. Dominion Energy Virginia's Subsection A 4 revenue requirement in this proceeding is based upon: (1) costs for transmission services provided to the Company by PJM, the regional transmission entity of which the Company is a member, according to applicable rates, terms, and conditions approved by the FERC; and (2) costs charged to the Company associated with demand response programs approved by the FERC and administered by PJM. I will refer to all of these costs collectively as "Subsection A 4 costs" in my testimony.

In particular, I will define and discuss how the following categories of costs were utilized to determine the revenue requirement in this proceeding:

<u>Current Subsection A 4 Costs</u>

These are the forecasted Subsection A 4 costs for the Rate Year sought to be recovered from Virginia retail customers.

<u>True-up of Subsection A 4 Costs</u>

This is the difference between the actual revenues received from Virginia retail customers for the recovery of Subsection A 4 costs and the actual Subsection A 4 costs incurred during calendar year 2024.

Update of Subsection A 4 Costs

This is an update of certain Subsection A 4 costs that will be incurred by the Company during the period January 1, 2025 – August 31, 2025 (the "Update Period") based upon known changes to components of the cost of service used to develop the Subsection A 4 rates currently in effect.

Q. Is your Schedule 1, consisting of Formula Schedules 1 through 10, consistently numbered with that presented in the 2024 Rider T1 Case?

A. Yes, it is.

II. SUBSECTION A 4 COSTS

Q. Before discussing the development of the Company's proposed revenue requirement, please describe the nature of the Subsection A 4 costs sought to be recovered from Virginia jurisdictional retail customers in this proceeding.

A. Subsection A 4 provides that certain costs incurred by the Company are deemed to be reasonable and prudent. This statutory provision also establishes broad guidelines for the recovery of these costs through retail rates. It reads in relevant part as follows:

> The following costs incurred by the utility shall be deemed reasonable and prudent: (i) costs for transmission services provided to the utility by the regional transmission entity of which the utility is a member, as determined under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission; [and] (ii) costs charged to the utility that are associated with demand response programs approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member; ….

Subsection A 4 also provides additional detail regarding specific costs that are recoverable through a RAC by directing that, upon petition by a public utility, "the

Commission shall approve a rate adjustment clause under which such costs, including, without limitation, costs for transmission service; charges for new and existing transmission facilities…; administrative charges; and ancillary service charges designed to recover transmission costs, shall be recovered on a timely and current basis from customers." The types of costs included in this filing are consistent with those previously approved for recovery by the Commission in the Company's prior Rider T/T1 cases.

The costs for services described in Subsection A 4 are derived from the FERC-approved tariff rates contained in the PJM Open Access Transmission Tariff ("PJM OATT"). PJM applies these rates to billing determinants as detailed on Formula Schedule 2. PJM billing determinants are defined as the units of measure used as PJM's bases for charging customers, including Dominion Energy Virginia, for services. Examples of billing determinants include megawatts ("MW") and megawatt-hours ("MWh"), among others. The resulting costs incurred by the Company are then allocated to the Virginia jurisdiction based on a Network Service Peak Load ("NSPL") allocation factor, or the energy allocation factor. The results of the foregoing calculations are the estimated current Subsection A 4 costs set forth in Formula Schedule 2. These resulting costs are the bases for the revenue requirement to be recovered through retail rates pursuant to Subsection A 4. Company Witness Batta provides a more detailed explanation of how these Subsection A 4 costs are developed at PJM.

Listed below are the five components of costs approved by the Commission for recovery in the Company's previous Rider T and T1 cases, and the related FERC-approved PJM services associated with those costs. Formula Schedule 2 elaborates on these components and demonstrates how they are used to derive the cost of service and, ultimately, the revenue requirement for recovery of Subsection A 4 costs to be incurred during the Rate Year. Formula Schedules 3 through 8 provide support for the data utilized in Formula Schedule 2. Formula Schedule 9 calculates the cost of service and the revenue requirement for the true-up component of all Subsection A 4 costs incurred during calendar year 2024, and reports the revenues intended to recover those costs. Finally, Formula Schedule 10 determines the cost of service and, ultimately, the revenue requirement for updating to certain known Subsection A 4 costs or rate changes incurred by the Company during the Update Period. The changes in the Update Period costs are included in this filing because the difference between the level of costs currently being billed by PJM, and the level of costs used to determine rates currently in effect, is now known for the Update Period.

The costs being recovered through this Subsection A 4 RAC include:

(1) **Costs for Transmission Service** – The FERC-approved Annual Transmission Revenue Requirement ("ATRR") uses the NITS tariff rate that PJM charges Dominion Energy Virginia as a transmission customer to determine its share of the costs associated with operation of, and investment in, the transmission system owned by Dominion Energy Virginia and operated by PJM, less offsetting revenue credits for Firm and Non-Firm Point-to-Point Transmission Service, plus an Underground Transmission Service charge associated with FERC Docket No. EL10-49-000. The Underground Transmission Service charge is described in more detail in the pre-filed direct testimony of Company Witness Batta.

(2) **Charges for New and Existing Transmission Facilities** – Transmission Enhancement Charges and Transmission Enhancement Credits from PJM to Dominion Energy Virginia are for transmission projects approved in the PJM RTEP, whereby PJM identifies and directs

the construction of enhancement or expansion projects, as required, to meet the demands for firm transmission service in the PJM region. Such projects often benefit customers of more than one utility. Therefore, the revenue requirements resulting from these designated projects are shared with other utilities based upon the benefits respectively provided. Net Transmission Enhancement Charges/Credits reflected on PJM's invoices include the allocated portion of other utilities' RTEP construction project revenue requirements for which Dominion Energy Virginia is responsible, and credits for Dominion Energy Virginia's own RTEP construction project revenue requirements for which other TOs are responsible. Other Charges, which are presented in the Transmission Enhancement section of Formula Schedule 2, Page 1 of 2, Lines 6-31, include Generation Deactivation Charges, Generation Deactivation Credits, and the Dominion Energy Virginia East/West Settlement. Each of these Other Charges is described in more detail by Company Witness Batta.

(3) **Administrative Charges** – These charges are billed to Dominion Energy Virginia by PJM to recover the costs associated with operating PJM, and for funding various organizations through schedules included in the PJM OATT.

(4) **Ancillary Service Charges Designed to Recover Transmission Costs** – These charges are billed by PJM to recover Dominion Energy Virginia's costs of Scheduling, System Control, and Dispatch Services. The Company currently recovers these costs through its NITS rate and, therefore, does not have a separately stated rate in the PJM tariff for these ancillary services.

(5) **Costs Associated with Demand Response Programs Approved by the FERC** – The PJM Emergency and Pre-Emergency Load Response Program is designed to provide a method by which curtailment service providers ("CSPs") may be compensated by PJM for customers' load

reduction during an emergency event, while the PJM Economic Load Response Program is designed to provide an incentive for customers of CSPs to reduce consumption when PJM energy market prices are high. The PJM Economic Load Response Program offers customers of CSPs the opportunity to participate in the PJM Energy Interchange Market, and to receive energy payments by curtailing load or self-generating, based on the locational marginal price ("LMP"), at their discretion.

Q. Does the Company expect any additions during the Rate Year to any of the types of cost components and/or services previously approved for recovery through the Subsection A 4 component of base rates or Rider T1?

A. No, it does not.

III. DETERMINATION OF THE REVENUE REQUIREMENT

Q. How did the Company develop the revenue requirement to recover the Subsection A 4 costs presented in this proceeding?

A. As stated previously and consistent with previous Rider T and T1 cases, the three main components of the revenue requirement proposed by the Company in this proceeding are: (1) current Subsection A 4 costs for the Rate Year of September 1, 2025 through August 31, 2026, in the amount of $1,122.9 million; (2) the true-up of the difference between the actual revenues received and the actual Subsection A 4 costs incurred during calendar year 2024 in the amount of $137.8 million; and (3) an update of Subsection A 4 costs for the Update Period based upon known rates, terms, and conditions applied to known billing determinants in effect during the Update Period in the amount of $82.6 million.

More specifically:

(1) The Subsection A 4 costs estimated to be incurred during the Rate Year are

determined by populating the portion of the Commission-approved revenue requirement formula in Formula Schedule 2 with the applicable FERC-approved rates from tariffs in effect on the date of this Application. In addition, the Company has populated the Subsection A 4 formula with projected billing determinants for the Rate Year, as well as the most current jurisdictional allocation factors for cost assignment. These annual formula inputs are further supported by Formula Schedules 3 through 8. The Subsection A 4 costs estimated to be incurred over the Rate Year are discussed in greater detail in Section IV of my testimony.

(2) Also included in this Application is a true-up of costs, as approved in previous Rider T and T1 cases, which compares Subsection A 4 costs actually incurred during calendar year 2024 to the Subsection A 4 revenues recovered from Virginia jurisdictional retail customers during calendar year 2024. Amounts invoiced to the Company for transmission services and demand response programs provided by PJM, the demand and energy allocation factors applicable for 2024, the credit for amounts previously recovered through prior update adjustments, the remaining annual amortization of unrecovered costs at August 31, 2023, over the period January through August 2024, and the annual amortization of unrecovered costs at August 31, 2024 over the period September through December 2024 – as well as the revenues intended to recover these costs incurred on behalf of Virginia jurisdictional retail customers – are all inputted into Formula Schedule 9 to calculate the true-up of 2024 Subsection A 4 costs. The

various cost components included in Formula Schedule 9 are discussed in greater detail below in Section V of my testimony.

(3) The third component of the Company's revenue requirement proposal, as presented in Formula Schedule 10, calculates an additional revenue requirement resulting from updating certain known Subsection A 4 costs or rate changes occurring during the Update Period. This update is necessary to facilitate the "timely and current" recovery of such costs, as required by Subsection A 4. Formula Schedule 10 reflects known changes in the levels of certain Subsection A 4 costs occurring during the Update Period by comparing the Update Period level of these costs to the levels of corresponding Subsection A 4 costs used to develop the cost of service underlying current Subsection A 4 rates from the 2024 Rider T1 Case. The Company is updating only Subsection A 4 cost changes that are known at the time of filing this Application to be in effect during the Update Period, and is not attempting to recalculate or re-estimate all Subsection A 4 costs. For this current Application, consistent with previous approvals, the Company proposes to recover the known Update Period cost changes for NITS and Transmission Enhancement Charges/Credits. The update of Subsection A 4 costs during the Update Period is discussed in more detail in Section VI of my testimony.

Q. Please summarize how the revenue requirement is developed in this proceeding for recovery of the Company's Subsection A 4 costs.

A. The total cost of service in this proceeding is derived by applying the actual FERC tariff rates charged by PJM under the PJM OATT to the Company in its capacity as a load-serving entity – *i.e.*, as the Dominion Energy Virginia Load Serving Entity ("DOMLSE"), the entity that is responsible for providing electric energy to Virginia jurisdictional retail customers in the Dominion Energy Virginia Zone (the "Dom Zone") within PJM.

These FERC tariff rates are applied to billing determinants to calculate Dominion Energy Virginia's Subsection A 4 costs, with five exceptions: (1) credits for Point-to-Point Transmission Service; (2) Dominion Energy Virginia Settlement Charges; (3) charges for Underground Transmission Service (Docket No. EL10-49); (4) Generation Deactivation Charges/Credits; and (5) charges for PJM's demand response programs. Due to their variable nature, the Point-to-Point Transmission service credits and the demand response programs charges are based upon the actual billings to DOMLSE per the monthly PJM invoices for the twelve months ending January 31, 2025. The charges for Underground Transmission Service (Docket No. EL10-49) have been projected based upon the incremental undergrounding costs revenue requirement calculated in Attachment 10 of the 2025 projection of Appendix A of Attachment H-16A to the PJM OATT. The Generation Deactivation Charges/Credits have been projected to be $0 because no amounts are expected to be incurred during the Rate Year. The Dominion Energy Virginia Settlement Charges are fixed monthly amounts determined by settlement approved in the appropriate FERC docket. All such costs are then allocated to the Virginia jurisdiction using the appropriate demand or energy allocators.

The Rate Year demand allocation factor for transmission capacity is derived from an NSPL allocation methodology. This demand allocation factor is based on the Virginia retail jurisdiction's contribution to the Dom Zone's or to DOMLSE's annual peak load, whichever is appropriate, for PJM's annual period ending October 31, 2024.

The estimated Rate Year energy allocation factor is consistent with the measurement of energy among all allocation methodologies and is based upon the Company's calendar year 2024 system operating results, subject to true-up. For example, NITS costs are allocated to Virginia jurisdictional customers based upon the demand allocator MW, while PJM administrative costs are allocated to Virginia retail customers based upon the energy allocator MWh. In short, the Company uses the same basis for allocation to Virginia jurisdictional retail customers consistent with the manner in which its previous Rider T and T1 cases were filed with and approved by the Commission.

IV. RECOVERY OF PROJECTED RATE YEAR COSTS

Q. Please discuss the Company's approved formula to recover Subsection A 4 costs incurred during the Rate Year from its Virginia jurisdictional customers.

A. Per the Commission's Final Orders in previous Rider T and T1 cases, Dominion Energy Virginia has estimated the Rate Year level of Subsection A 4 costs by populating the formula with amounts derived from FERC-approved rates available at the time of filing this Application. Dominion Energy Virginia has included in the formula each of the components necessary to appropriately estimate the Subsection A 4 costs for the projected Rate Year in this proceeding, subject to Commission review and approval. The inputs used to calculate the forward-looking Rate Year consist of actual tariffs and rates, billing determinants for the Rate Year, and the most current jurisdictional allocation factors for cost assignments.

Q. Please describe how the formula works.

A. Formula Schedule 2 estimates the revenue requirement for costs to be incurred during the Rate Year according to the same cost categories described in Subsection A 4 – which were approved by the Commission in previous Rider T and T1 cases – and discussed earlier in my testimony. These costs include: costs for transmission service, charges for new and existing transmission facilities (*i.e.*, transmission enhancement), administrative charges, transmission-related ancillary service charges (included in the NITS rate), and costs of PJM-administered demand response programs. Each cost category is supported by: (1) rates from the PJM OATT approved by the FERC and posted on the PJM website;[1] (2) Rate Year billing determinants based upon projections posted on the PJM website, as developed by the Company or derived from historical PJM invoices; (3) projections or historical actual dollar amounts supported by PJM invoices;[2] and/or (4) FERC-approved settlement agreements in the case of Dominion Energy Virginia Settlement Charges. The formula calculates a revenue requirement by multiplying these relevant billing determinants by the applicable tariff rates or by forecasting certain items based on historically incurred costs, FERC-approved settlement agreements, or known changes. Costs are then allocated to Virginia jurisdiction retail customers consistent with the manner in which previous Rider T and T1 cases were filed with and approved by the Commission.

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[1] *See www.pjm.com.*

[2] Point-to-Point Transmission Service Credits, Economic Load Response Program costs, and energy-related Emergency and Pre-Emergency Load Response Program costs are based on actual historical amounts derived from PJM invoices.

Q. Please describe the calculation of the revenue requirement in this proceeding for Subsection A 4 costs incurred during the Rate Year for each of the cost components described above.

A. Formula Schedule 2 presents the formula, along with all of the necessary cost components, for calculating the revenue requirement for each component of Subsection A 4 costs. The first component of the formula starts with the costs for transmission services, otherwise known as the NITS charges.

NITS costs are derived from the ATRR billed by the transmission provider (*i.e.*, PJM) based upon the current NITS tariff rate. The billing determinants applied to the NITS rate for calendar year 2025 network integration transmission service are based upon transmission demands at the time of the NSPL for the Dom Zone during the twelve months ending October 31, 2024. Transmission demand for the customers serviced by DOMLSE totaled 18,276.3 MW at the time of the 2024 Dom Zone NSPL.

Q. Please continue your discussion of the NITS rate.

A. The annual NITS rate of $75,876.81 per MW is applied to the DOMLSE transmission demands described above to calculate the NITS expense. The NITS expense is reduced by the Firm and Non-Firm Point-to-Point Transmission Service revenue credits (reported on Formula Schedule 3) and increased by the Underground Transmission Service charge. The net result equates to a DOMLSE revenue requirement of $1,378.2 million. The Virginia jurisdictional revenue requirement for this component, after allocation, is $1,174.9 million based upon the transmission demands of Virginia jurisdictional retail customers coincident with the Dom Zone peak demand.

Q. How has the Company projected the revenue requirement necessary to recover the second component of costs – *i.e.*, the net Transmission Enhancement Charges or Credits billed by PJM?

A. The net Transmission Enhancement Charges/Credits consist of three components. The first is a charge that occurs when PJM bills Dominion Energy Virginia for its allocated portion of the revenue requirements for RTEP projects constructed by all TOs in PJM, including the Company's own projects, that benefit the Company and that the FERC has approved for recovery. The second component is a credit that consists of the revenue requirements for all RTEP projects constructed by the Company and billed by PJM per Schedule 12 of the PJM OATT, and recovered from all TOs within PJM that benefit from the projects. This credit fully offsets the project costs included in the NITS rate, so that the net charge to Virginia jurisdictional retail customers is the amount that PJM bills the Company for (1) Dominion Energy Virginia's own RTEP projects allocated to Virginia jurisdictional customers, and (2) Dominion Energy Virginia's allocated share of costs from the RTEP projects of every other TO within PJM allocated to Virginia jurisdictional customers. The third component is the "Other" category, which includes the Generation Deactivation Charges/Credits and a Dominion Energy Virginia Settlement Charge for the East/West Settlement.

PJM publicly posts on its website the FERC-approved formulas used by each TO within the PJM service territory to calculate the ATRR and the resulting NITS rate. Specifically, these formulas can be found in the Markets & Operations, Billing, Settlements & Credit, and Formula Rates section of PJM's website. An attachment to each of these formulas contains a listing of individual RTEP projects and the associated annual revenue requirements for these projects. Also publicly posted on the PJM website, per Schedule 12 of the PJM OATT, are the allocation ratios necessary to split the revenue requirement for each such RTEP project among all TOs within PJM.

In addition, the Transmission Enhancement Worksheet posted on the PJM website in the Markets & Operations, Billing, Settlements & Credit section consolidates the latest available RTEP project revenue requirements from the formula rates section with the associated allocation ratios as provided by Schedule 12. The Company has calculated the revenue requirement associated with Transmission Enhancement Charges by multiplying the annual RTEP project revenue requirements by the applicable Dominion Energy Virginia allocation ratios, as provided by the Transmission Enhancement Worksheet.

PJM billings for RTEP projects, termed Transmission Enhancement Charges (developed on Formula Schedule 4) on the PJM invoices, consist of the sum of the revenue requirements associated with all TO projects attributable to the Dom Zone, including the Company's own projects. As shown on Formula Schedule 2, using the latest available data, this translates to a Virginia jurisdictional revenue requirement of $245.8 million. The Transmission Enhancement Credits (developed on Formula Schedule 5 and allocated to the Virginia jurisdiction on Formula Schedule 2) are the sum of all the recoveries of the revenue requirements for the Company's own RTEP projects as billed per Schedule 12 of the PJM OATT, which reduces the revenue requirement by $321.9 million on a Virginia jurisdictional basis. The "Other" component of the net Transmission Enhancement Charges/Credits includes Generation Deactivation Charges of $0.0 million, Generation Deactivation Credits of $0.0 million, and Dominion Energy Virginia

Settlement Charges of $3.0 million on a Virginia jurisdictional basis. This produces a net Virginia jurisdictional Transmission Enhancement Credit of $73.1 million.

Q. Please describe how Dominion Energy Virginia will recover the third component of Subsection A 4 costs sought in this case – the PJM administrative charges approved in previous Rider T and T1 cases.

A. The PJM administrative charges requested in this proceeding consist of charges for the following administrative services: control area and dispatch and financial transmission rights ("FTRs"). All these costs that the Company has incorporated for recovery through this proceeding are consistent with those that the Commission has approved for recovery in previous Rider T and T1 cases. Regulation and Frequency Response administrative charges that have previously been recovered through Rider T1 are not included in the revenue requirement beginning with the 2022 Rider T1 Case due to a change in the PJM billing for these costs, which Company Witness Batta discusses. For projected PJM administrative charges to be recovered in this proceeding, the Company uses billing determinants and rates provided in various subsections of Schedule 9 of the PJM OATT – *i.e.*, the same rates and billing determinants actually used by PJM to bill the Company for those respective administrative charges. The rates contained in the PJM OATT that are used to bill for PJM administrative charges are supplemented monthly and posted publicly on the PJM website. In other words, these subsections from Schedule 9 of the PJM OATT contain the specific types of billing determinants and rates necessary to calculate the total amount of the administrative charges recoverable in a Subsection A 4 proceeding per the Commission's Final Orders in the Company's previous Rider T and T1 cases.

The rates supporting the PJM administrative charges component of the Subsection A 4 costs are based on the January 2025 updates to the rates currently included in Schedule 9 of the PJM OATT for calendar year 2025 – *i.e.*, those rates used for billing purposes in January 2025. The majority of dollars included for recovery through the Subsection A 4 proceeding for PJM administrative charges is based upon the Company's projections of billing determinants for the Rate Year. When projecting billing determinants for the remaining administrative charges, the Company uses billing determinants based upon actual PJM billing history for the twelve months ending January 31, 2025, as a proxy for the Rate Year. The allocation basis used to distribute PJM administrative charges from DOMLSE to the Virginia jurisdiction is consistent with the method used in prior Rider T/T1 cases. Dominion Energy Virginia uses an energy allocation factor for costs billed by PJM based on the number of MWh or FTR bid obligations/options. I will now discuss the revenue requirement associated with each such subsection of PJM administrative charges in more detail.

<u>Schedule 9-1, Control Area Administrative Service</u>

PJM charges DOMLSE and other PJM members that use Point-to-Point Transmission Service and NITS a yearly administrative fee based on the number of MWh delivered by PJM on behalf of users, including DOMLSE. The Company has projected the level of MWh to be delivered for the Rate Year in this case. The Yearly Control Area Administration Service Rate in PJM OATT Schedule 9-1, reflecting the January 2025 update, is applied to these annual MWh for the Rate Year to calculate the projected costs for this PJM administrative fee of $24.4 million for DOMLSE. An energy allocation factor is then applied to this figure to produce a Virginia jurisdictional revenue requirement of $20.1 million.

Schedule 9-2, Financial Transmission Rights Administration Service

FTR Service Rate, Component 1

PJM charges DOMLSE and other PJM members that are allocated FTRs an administrative fee based on all FTRs awarded by PJM, using the amount of the Company's owned MW capacity times the number of hours per year. The result is the MWh billing determinant. For the Rate Year, the Company uses the MWh billing determinant based upon PJM's billing history for the twelve months ending January 31, 2025, to determine this fee. The FTR Service Rate, Component 1 in PJM OATT Schedule 9-2, which reflects the January 2025 update, is applied to these annual MWh and produces DOMLSE costs in the amount of $175,497 for this administrative service fee. An energy allocation factor is then applied to determine a Virginia jurisdictional revenue requirement of $144,605.

FTR Service Rate, Component 2

PJM charges an administrative fee to DOMLSE and other PJM members that participate in PJM's annual and monthly FTR auctions. This fee is based on the number of hours of FTR obligations/options purchased by the Company. For the Rate Year, the Company uses the "number of hours of FTR Obligations" and the "FTR Options purchased (multiplied by five)" billing determinants based upon PJM's billing history for the twelve months ending January 31, 2025 in determining this fee. The FTR Service Rate, Component 2 in PJM OATT Schedule 9-2, reflecting the January 2025 update, is applied to the annual hours of FTR Obligations/Options to produce DOMLSE costs in the amount of $0 for this administrative service. Formula Schedule 2, Page 1, Column 6, Lines 36-37 show the elements of this total amount. An energy allocation factor is then applied to determine a Virginia jurisdictional revenue requirement of $0, as shown by adding Lines 36-37 of Formula Schedule 2, Page 1, Column 9.

<u>**Schedule 9-FINCON, Financial Committee Retained Outside Consultant**</u>

The Company is not estimating this cost due to a lack of billing activity by PJM during the most recent twelve-month period, and because any potential charges are expected to be small. The actual costs for this fee, if any, will be recovered through the true-up mechanism in a future Subsection A 4 proceeding.

Q. What is the overall revenue requirement impact of these PJM administrative charges sought to be recovered in this proceeding?

A. The total sum of the PJM administrative charges described above produces a Virginia jurisdictional revenue requirement of $20.2 million for this Subsection A 4 proceeding. Again, these costs are consistent with the administrative charges approved by the Commission for recovery in the previous Rider T and T1 cases.

Q. The last component of formula costs to be recovered in this proceeding is the demand response programs, which include both the Economic and the Emergency and Pre-Emergency Load Response Programs administered by PJM. Please describe the method used by the Company to develop the energy-related portion of these Programs' costs.

A. Because participation in these Programs can fluctuate from year to year, the resulting costs can also vary dramatically. Due to this inherent variability, the Company is unable to forecast the costs of these programs. Therefore, the Economic Load Response Program and Emergency and Pre-Emergency Load Response Program costs included in the Company's cost of service for the energy-related costs of the Programs are set at the actual level of costs for the twelve-month period February 2024 through January 2025, consistent with previous Rider T and T1 cases. The components of Subsection A 4 costs related to these Programs are energy-related costs. As such, they are apportioned using an energy allocation factor for purposes of estimating Subsection A 4 costs. Formula Schedule 2, Page 1, Column 9, Line 40 shows an increase to the Virginia jurisdictional revenue requirement of $926,758 for these Programs.

Q. The Company's Application may contain both charges and credits associated with its participation in the PJM Economic Load Response Program. Please describe the Company's treatment of these charges and credits in this Subsection A 4 proceeding.

A. The Company, for its CSP account ("DOMCSP"), elected to participate in the Economic Load Response Program and receive energy payments based on the LMP of energy when demand and the associated LMP were extremely high. When DOMLSE is determined by PJM to be a beneficiary of Economic Load Response, it is charged by PJM for this Program. When the Company participates in providing Economic Load Response, it receives a credit for its load reductions. Both charges and credits, to the extent invoiced to the Company, are included in this current proceeding.

Q. Please summarize the calculation of the projected Rate Year level of Subsection A 4 costs that Dominion Energy Virginia seeks to recover through application of its previously approved formula.

A. Unless otherwise noted, each cost item described earlier in my testimony is separately listed as a line item in Formula Schedule 2. Each line item contains a description of the pertinent costs, a description of the billing determinant used, the type of billing determinant (*e.g.*, energy, demand, hour, months, and amounts), the DOMLSE billing determinant, the allocation factor designed to produce a Virginia jurisdictional level of costs, the rate derived from the PJM OATT and/or the PJM website service rate update, and the resulting revenue requirement. Work papers and supporting documents are included in Filing Schedule 46A, Statement 12, which reflect the determination of these allocation factors, the DOMLSE billing determinants, and the PJM OATT rates.

The Virginia jurisdictional projected revenue requirement for the Rate Year Subsection A 4 costs in this proceeding totals $1,122.9 million, as shown on Column 9, Line 42 in Formula Schedule 2. In addition to these costs projected over the Rate Year, the revenue requirement also includes the true-up component of actual 2024 calendar year costs as compared to the actual revenues designed to recover those costs and an update for the difference between known Subsection A 4 costs that will be incurred by the Company for the Update Period and those same components of the cost of service used to develop the Subsection A 4 rates currently in effect. I will next discuss the true-up component of the revenue requirement, followed by a detailed discussion of the update calculation.

V. TRUE-UP OF CALENDAR YEAR 2024 COSTS

Q. Please discuss the true-up mechanism designed to recover the actual amount of Subsection A 4 costs incurred during 2024, and identify the sources of the costs and revenues used for calculating this true-up.

A. Dominion Energy Virginia's true-up formula, which is set out in Formula Schedule 9, has been populated with actual Subsection A 4 costs taken directly from the Company's monthly PJM invoices for the calendar year ended December 31, 2024. These costs have been allocated to Virginia jurisdictional customers based on either demand or energy factors. The transmission demand allocator is based on the NSPL for the twelve months ended October 31, 2023. The energy allocator is based on the delivery of MWh to DOMLSE for calendar year 2024.

The actual costs shown on the 2024 PJM invoices included in Filing Schedule 46A were allocated to Virginia jurisdictional retail customers and then compared to the revenues actually collected from those customers based upon the rates in effect and approved in the 2023 Rider T1 Case for the period January 1 through August 31, 2024, as well as the revenues generated by the rates in effect and approved in the 2024 Rider T1 Case for the period September 1 through December 31, 2024.

Q. Please describe each component of the true-up calculation presented in Formula Schedule 9.

A. For convenience and ease of reference, I will discuss each component of the Subsection A 4 costs and retail revenues included in the true-up calculation in detail in the order that they appear on Formula Schedule 9. All of the Subsection A 4 costs identified previously in my testimony are included in this true-up mechanism.

Transmission Service Charges

The first component of Subsection A 4 costs to be trued-up is the NITS charge billed to the Company by PJM. The amounts for the NITS charge, the revenue credits for both Firm and Non-Firm Point-to-Point Transmission Services, and the Underground Transmission Service charge were taken directly from the PJM invoices billed to DOMLSE in each month of calendar year 2024. These monthly amounts were then allocated to Virginia jurisdictional customers using the appropriate 2023 DOMLSE transmission demand allocation factor to derive the NITS charges subject to recovery during the year.

For the twelve months ending December 31, 2024, the total amount of NITS charges for transmission service, including the Underground Transmission Service charge net of revenue credits for Point-to-Point Transmission Service billed to the Company by PJM, amounted to $1,029.0 million on a Virginia jurisdictional basis, as shown in Formula Schedule 9, Column 16, Line 8. The Underground Transmission Service charge is described more fully in the pre-filed direct testimony of Company Witness Batta.

Transmission Enhancement Charges/Credits

The second component of Subsection A 4 costs subject to true-up is the net Transmission Enhancement Charges/Credits billed to DOMLSE via the monthly invoices from PJM. Transmission Enhancement Charges/Credits consist of several components. The first is a charge that PJM bills the Company for the Company's allocated portion of the costs associated with RTEP projects (subject to Schedule 12 of the PJM OATT) constructed by all TOs within PJM, including the Company's own projects. These charges are referenced on Formula Schedule 9, Line 9.

The Company also receives a credit for the revenue requirements for all RTEP projects subject to Schedule 12 of the PJM OATT constructed by the Company. Formula Schedule 9, Line 10 shows these credits from the PJM bill by month.

There are three additional PJM items included in the 2024 Transmission Enhancement section of Formula Schedule 9. The Dominion Energy Virginia Settlement charges related to the East/West Settlement, as shown on Formula Schedule 9, Line 11, are taken directly from the PJM invoices. The net Generation Deactivation Charges/Credits, as shown on Formula Schedule 9, Lines 12 and 13, are also taken directly from the PJM invoices. The Dominion Energy Virginia Settlement and the net Generation Deactivation Charges/Credits are described more fully in the pre-filed direct testimony of Company Witness Batta.

The net monthly amount of Transmission Enhancement Charges/Credits is then allocated to Virginia jurisdictional customers using the 2023 DOMLSE transmission demand allocation factor. Note, however, that this allocation is based on a system amount representing charges to DOMLSE, whereas the factor used to allocate these same net Transmission Enhancement Charges/Credits for the estimated Rate Year is based on a system amount representing the Dom Zone. This is because net Transmission Enhancement Charges/Credits are billed to DOMLSE per the PJM invoices, while the charges derived from the outstanding PJM OATT tariff represent Dom Zone cost levels. For the twelve months ending December 31, 2024, the net amount of Transmission Enhancement Charges/Credits attributed to the Company by PJM and subject to true-up amounted to a $47.0 million credit on a Virginia jurisdictional basis. Formula Schedule

9, Line 15 displays the 2024 monthly breakdown of the net Transmission Enhancement Charges/Credits.

PJM Administrative Charges

The third component of Subsection A 4 costs to be trued up is the amount of applicable PJM administrative charges billed to the Company from January 1 through December 31, 2024. The PJM administrative charges billed to DOMLSE can be referenced on Lines 16-19 of Formula Schedule 9. The total PJM administrative charges for the twelve months ending December 31, 2024, are $25.3 million, as shown in Column 16, Line 20 of Formula Schedule 9. The total DOMLSE amounts were then allocated to Virginia jurisdictional customers using the 2024 energy allocation factor to derive the actual calendar year PJM administrative charges subject to true-up totaling $20.9 million, as shown on Formula Schedule 9, Column 16, Line 21.

Demand Response Programs

The final components of Subsection A 4 costs subject to true-up are the charges for the PJM Economic and Emergency and Pre-Emergency Load Response Programs. As previously discussed, the Economic Load Response Program consists of energy payments to participants for voluntary reductions in consumption based on economic conditions, such as the price of energy in the PJM energy markets, while the Emergency and Pre-Emergency Load Response Program has the potential for both energy and capacity payments for participants.

The energy charges for both the Economic and Emergency and Pre-Emergency Load Response Programs are taken from monthly PJM invoices and are included on Line 22 of

Formula Schedule 9. The total amount of net energy charges received by the Company for both the Economic and Emergency and Pre-Emergency Load Response Programs in 2024 was $1,279,146. The energy charges and credits related to the emergency events that occurred in calendar year 2024 are included on this line in the 2024 true-up calculation. The 2024 DOMLSE energy allocator was applied to this net system amount to derive the Virginia jurisdictional balance subject to true-up of $1,053,987 presented on Formula Schedule 9, Column 16, Line 23.

Q. Next, please describe the Amortization of Deferred Costs item listed on Line 25 of Formula Schedule 9.

A. This line item includes the amortization of any prior period under- or over-recovered amounts. To match cost recognition with revenue recoveries, Line 25 of Formula Schedule 9 captures the straight-line amortization of any under- or over-recovered balances recorded on the books at the beginning of a rate year for recovery from (or credit to) Virginia jurisdictional customers over the twelve months beginning September 1 of the succeeding rate year. Any actual over- or under-recovered balance as of August 31 is amortized using the straight-line method based on a daily rate over the September 1 through August 31 rate year. In this proceeding, for the months of January through August 2024 (Columns 4 through 11), Line 25 reflects the monthly amortization of the remaining under-recovered balance as of August 31, 2023. For the months of September through December 2024 (Columns 12 through 15) on Line 25 of Formula Schedule 9, the actual under-recovered balance as of August 31, 2024, is amortized using the straight-line method based on a daily rate over the rate year September 1, 2024, through August 31, 2025.

Q. Please describe how Line 26 of Formula Schedule 9, Calculation of the Monthly True-Up Adjustment, accommodates the Update Period adjustment.

A. Line 26 of Formula Schedule 9, the Monthly True-Up Adjustment schedule, was established to ensure that a duplication of cost recovery or reduction between the Formula Schedule 10 Update Period adjustment and the true-up does not occur. The Update Period adjustment allows for the more timely recovery of costs incurred during the Update Period, even though revenues will not start to be recovered for the current Update Period until September 1 of each year. Costs for the Update Period in the calendar year subject to true-up will generally be higher than the level of Update Period revenues collected for the calendar year subject to true-up. Because the recovery of these costs, as a result of the Update Period adjustment, will commence by September 1 of each year, those same Update Period costs will be excluded from recovery for the period January 1 through August 31 during the calendar year subject to true-up. Thus, the monthly Update Period adjustment amounts on Line 26 taken from the previous year's Formula Schedule 10 adjust this year's amount of Subsection A 4 costs subject to true-up. Line 26 is populated with the 2024 monthly Update Period adjustment amounts appearing on Formula Schedule 10, Columns 4 through 11, Line 15 consistent with the Commission's order approving the revenue requirement in the 2024 Rider T1 Case. Because the Update Period adjustment amounts on Line 26 represent a recovery of additional costs, the monthly amounts reduce the costs subject to true-up for this proceeding, which prevents double recovery of the Update Period adjustment amount.

Q. Please describe the overall results of the 2024 true-up calculation as represented in Formula Schedule 9.

A. The Company was billed a total of $1,003.9 million by PJM for Subsection A 4 costs on a Virginia jurisdictional level for calendar year 2024, as noted in Formula Schedule 9, Column 16, Line 24. The costs billed by PJM for the Update Period of January 1 through August 31, 2024, are reduced by the amount of costs included in current rates through the Update Period adjustment mechanism approved by the Commission in the 2024 Rider T1 Case, and then the remaining costs for January through December 2024 are adjusted by the amortization of the deferred amounts discussed above. These adjusted 2024 costs, which represent the total costs subject to true-up, are then compared to the actual Virginia jurisdictional retail revenues intended to recover Subsection A 4 costs received in calendar year 2024 to determine the over- or under-recovery of Subsection A 4 costs for the year. A comparison of the Virginia jurisdictional retail revenues received in 2024 of $935.4 million (Formula Schedule 9, Column 16, Line 28) to the Company's actual Subsection A 4 costs subject to true-up for 2024 shows an under-recovery of $137.8 million (Formula Schedule 9, Column 16, Line 29) in this proceeding.

I will now discuss the proposed Update Period adjustment and its impact on the Company's revenue requirement in this proceeding.

VI. 2025 UPDATE PERIOD COSTS

Q. Please discuss the recovery of known cost changes occurring during the Update Period for this Application.

A. As initially approved by the Commission in the 2010 Rider T Case, this adjustment allows for under- or over-recoveries arising from changes in FERC-approved rates and billing determinants that are known to occur during the Update Period to be built into rates for recovery or credit beginning September 1 of each rate year, instead of being delayed until much later when calendar year Subsection A 4 costs and revenues intended to recover Subsection A 4 costs are trued up.

The known costs that the Company is updating in this proceeding include the same types of costs that were approved for recovery by the Commission in the 2024 Rider T1 Case – *i.e.*, they are costs for transmission services provided to the Company by PJM under the FERC-approved PJM OATT and Transmission Enhancement Charges/Credits.

The costs for the Update Period are also based on charges billed by PJM using FERC-approved rates, terms, and conditions known at the time of filing this Application and in effect during the Update Period. For example, the ATRR included in the 2024 Rider T1 filing was based upon the NITS rate approved by FERC for calendar year 2024 and was the latest known at the time of the 2024 Rider T1 Application filing. The 2025 ATRR based on the latest NITS rate approved for use by the Company for calendar year 2025 was not available at the time of that filing and, therefore, could not have been used in that Application. Thus, the Company is using the same bases for determining costs for the Update Period as for the Rate Year in this proceeding. The latest FERC-approved rates known to be in effect for the Update Period applied to known billing determinants are also the same rates applied to the same billing determinants used to develop the Subsection A 4 costs for the Rate Year.

Q. What is the total revenue requirement for the expected under-recovery of Subsection A 4 costs for the Update Period in this proceeding?

A. As shown in Formula Schedule 10, the Company has determined an under-recovery of Subsection A 4 costs for the Update Period in the amount of $82.6 million to be included in this Application. These total costs are derived from the following: (1) increases in the ATRR resulting from the NITS tariff effective January 1, 2025; and (2) offset partially by a net decrease in the amount necessary to recover the current net credit level of Transmission Enhancement Charges/Credits for the Update Period.

Q. Why did the Company select these two components of Subsection A 4 costs to update instead of updating all Subsection A 4 costs?

A. In an approach previously approved by this Commission, the Company has limited the update of Subsection A 4 costs to known cost changes as of the date of this Application filing. These changes are derived from rates and billing determinants that will be in effect during the Update Period, as compared to the respective amounts currently being recovered through the existing Subsection A 4 component of base rates and Rider T1. The Subsection A 4 costs included for updating represent the current levels of costs being billed by PJM for NITS charges and net Transmission Enhancement Charges/Credits. Again, the Update Period adjustment is not an effort to update all Subsection A 4 costs, but rather to identify known material cost or rate changes that are incurred during the Update Period to allow for the more timely and current recovery of these costs as required by Subsection A 4.

In each of these components of the cost of service, the applicable, currently effective FERC-approved rates reflect rate changes that have occurred since the Company's

Application filing in the 2024 Rider T1 Case, and that will be in effect during the Update Period. Accordingly, they have been included for updating, which produces an increase to the revenue requirement in the amount of $95.7 million for NITS, and a net decrease of $13.1 million for net Transmission Enhancement Charges/Credits. Thus, the total portion of the revenue requirement resulting from updating these cost components is an increase of $82.6 million.

Q. Are there any Subsection A 4 costs that have not been adjusted in the Update Period?

A. Yes. Consistent with the methodology approved in prior Rider T and T1 cases, there are several components of Subsection A 4 costs that did not warrant updating prior to being addressed in the true-up process in a subsequent Subsection A 4 proceeding. Point-to-Point Transmission Service revenue credits, as noted previously, can vary significantly from period to period and are, therefore, difficult to project. The item for Underground Transmission Service (Docket EL10-49) related to three underground transmission projects is expected to have relatively stable costs in future years. Therefore, it does not need to be updated. The item for Dominion Energy Virginia Settlement EL 05-121-009 related to the East/West Settlement is subject to periodic cost changes. Thus, this item has not been updated. Generation Deactivation Charges/Credits that have been incurred in prior years are not expected to be incurred during the Rate Year. Thus, there is no need for an update to this amount. Likewise, because the PJM administrative charges are subject to periodic cost changes, specific amounts are not currently known for the Update Period. Finally, amounts for energy-related demand response program charges tend to be very small and can fluctuate depending on each period's operating conditions. Thus, due to the nature of each of these charges, they will be addressed in the true-up process in a subsequent Subsection A 4 proceeding, as needed.

Q. How is the Update Period adjustment incorporated into the formula schedules?

A. As first approved by the Commission in the 2010 Rider T Case, the Update Period adjustment is presented in Formula Schedule 10 and develops an increment or decrement between updated levels of the appropriate Subsection A 4 costs, as compared to those same costs used to develop the cost of service supporting the Subsection A 4 rates currently in effect. Formula Schedule 10 updates the previously described Subsection A 4 costs to current levels in the Update Period. The update is performed in Formula Schedule 10 by comparing the levels of Subsection A 4 costs known at the time of filing this Application, and billed by PJM for the Update Period, to the amounts included in the cost of service supporting the Subsection A 4 rates currently in effect. For the two Subsection A 4 cost components – NITS and Transmission Enhancement Charges/Credits – considered in the Update Period adjustment, the annual updated level of costs in Formula Schedule 10, Column 2, Lines 6-8, is equivalent to the costs included on Formula Schedule 2, Page 1 of 2, Column 9, Lines 1, 25, and 27, respectively, for the Rate Year.

VII. CONCLUSION

Q. Please discuss in more detail the primary drivers of the increase in this year's total revenue requirement over that approved in the 2024 Rider T1 Case.

A. The total Subsection A 4 revenue requirement consists of three primary components: the projected Subsection A 4 costs, the true-up adjustment, and the Update Period adjustment. Overall, the total revenue requirement in this Application increased by approximately $173.7 million relative to the revenue requirement approved for recovery by the Commission in the 2024 Rider T1 Case. See the table below for a breakdown of this figure:

(Dollars in Millions)

Primary Components of the Revenue Requirement	Rate Year Beginning Sep 1, 2025	Rate Year Beginning Sep 1, 2024	Change
Projected Subsection A 4 Cost of Service	$1,122.9	$1,010.0	$112.9
True-up Adjustment	137.8	93.7	44.1
Update Adjustment	82.6	65.9	16.7
Total Revenue Requirement	$1,343.3	$1,169.6	$173.7

The following is a listing of each component/subcomponent of the revenue requirement and its change relative to what was approved for recovery in the 2024 Rider T1 Case, with a description of the drivers of the change for the items that changed significantly.

The projected Subsection A 4 costs are the first primary component of the revenue requirement and have four subcomponents. The first of these is the NITS subcomponent, which is the major line item in Rider T1. It contains the projected NITS costs billed to the Company by PJM. This line item increased by $139.4 million, due largely to the increase in the NITS formula rate charged to the Company by PJM. The main driver of the increase in this rate is the Company's additional transmission plant in-service, which is a component of the NITS formula rate and is described in the pre-filed direct testimony of Company Witness Batta.

The second subcomponent of the projected Subsection A 4 costs is the net Transmission Enhancement Charges/Credits, which decreased the revenue requirement by $25.8 million. This item decreased because of the increase in the Transmission Enhancement Charges of $23.4 million, the decrease to the revenue requirement due to the increase in Transmission Enhancement Credits of $43.1 million, no change to the revenue requirement due to the Generation Deactivation Charges/Credits of $0.0 million, and a decrease to the revenue requirement due to the East/West Settlement of $6.1 million.

The third subcomponent of the projected Subsection A 4 costs is the PJM administrative charges, which increased the revenue requirement by $0.5 million. The most significant change in this subcomponent is an increase in the Control Area costs of $0.5 million. Changes to the other administrative charges line items netted a small increase in the revenue requirement that rounds to $0.0 million.

The fourth subcomponent of the projected Subsection A 4 costs is the demand response programs approved by FERC. This item decreased the revenue requirement by $1.2 million.

The true-up adjustment is the second primary component of the revenue requirement. This item increased the revenue requirement by $44.1 million. There are many items that affect the amount of the true-up adjustment. At a high level, however, the 2024 revenues were $208.2 million more than the 2023 revenues and the 2024 costs were $252.3 million more than the 2023 costs. The 2023 revenues and costs are from the 2024 Rider T1 Case.

The Update Period adjustment for January – August 2025 is the third primary component of the revenue requirement. This item increased the revenue requirement by $16.7 million. There was a $28.3 million increase in the change in the NITS expense between 2025 and 2024 relative to the change between 2024 and 2023. There was a $20.8 million decrease in the change in the Transmission Enhancement Charges for the increase between 2025 and 2024 relative to the increase between 2024 and 2023. There was a $9.2 million increase in the change in the Transmission Enhancement Credits due to the increase in credits between 2025 and 2024 relative to the increase in these credits between 2024 and 2023.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS OF DAVID M. WILKINSON

David M. Wilkinson received a Bachelor of Science degree in Business Administration and Accounting from Washington & Lee University in 1985 and a Master of Business Administration degree from the University of Richmond in 1994. He is also a Certified Public Accountant. Prior to joining the Company in January 1998, he had over ten years of experience in public accounting and industry. During his career with the Company, he has held numerous staff and managerial positions in finance and regulatory accounting. Currently, his position is Manager – Regulation in the Regulatory Accounting department, with responsibility for analyzing and calculating revenue requirements for Dominion Energy Virginia rate proceedings.

Mr. Wilkinson has previously submitted testimony before the State Corporation Commission of Virginia and the Federal Energy Regulatory Commission.

Virginia Electric and Power Company
Subsection A 4 Costs
Calculation of Cost of Service - Summary
For the Rate Year Beginning September 1, 2025
Virginia Jurisdiction

Line No.	Component	Amount	Item Location
1	Network Integration Transmission Service	$ 1,174,910,474	Formula Schedule 2; pg 1 of 2; Col. 9; Line 5
2	Transmission Enhancement Charges/Credits	(73,135,755)	Formula Schedule 2; pg 1 of 2; Col. 9; Line 32
3	PJM Administrative Charges	20,212,445	Formula Schedule 2; pg 1 of 2; Col. 9; Line 38
4	Demand Response Programs Approved by FERC	926,758	Formula Schedule 2; pg 1 of 2; Col. 9; Line 41
5	Subtotal - Subsection A 4 Cost of Service (sum of Lines 1 through 4)	**$ 1,122,913,922**	
6	True-up Adjustment	137,839,726	Formula Schedule 9; pg 1 of 1; Col. 16; Line 29
7	Update - January 2025 to August 2025	82,582,087	Formula Schedule 10; pg 1 of 1; Col. 12; Line 15
8	Total Subsection A 4 Cost of Service (Line 5 + Line 6 + Line 7)	**$ 1,343,335,735**	

Virginia Electric and Power Company
Subsection A 4 Costs
Calculation of Cost of Service Based on PJM Charges
For the Rate Year Beginning September 1, 2025
Virginia Jurisdiction

Col. No.	1		2	3	4	5	6	7	8	9
Line No.	Description		Description Billing Determinant	Type Billing Determinant	Billing Determinant (a)	Rate (a)	Transmission Expenses (col. 4 * col. 5)	Virginia Juris. Allocator (a)	Allocator Description	Virginia Juris. Transmission Expenses (col. 6 * col. 7)
1	**Network Integration Transmission Service (NITS)**		Transmission Demand	MW	18,276.3	75,876.81	$ 1,386,747,357	85.2236%	Demand - DOMLSE	$ 1,181,835,731
2	Firm Point-to-Point Transmission Service		Fixed Amounts - Dollars - Historical	$	(15,789,493)		(15,789,493)	85.2236%	Demand - DOMLSE	(13,456,371)
3	Non-Firm Point-to-Point Transmission Service		Fixed Amounts - Dollars - Historical	$	(2,389,344)		(2,389,344)	85.2236%	Demand - DOMLSE	(2,036,284)
4	Underground Transmission Service (Docket EL10-49)		Fixed Amounts - Dollars - PJM OATT	$	9,651,813		9,651,813	88.7647%	Demand - DOMLSE - MODIFIED	8,567,399
5	**Net Network Integration Transmission Service (NITS)**						$ 1,378,220,332			$ 1,174,910,474
6	**Transmission Enhancement Charges (Schedule 12 - PJM OATT)**	(b)								
7	Atlantic City Electric Company		Fixed Amounts - Dollars - Annual	$	159,815	Various	$ 159,815	68.8874%	Demand - DOMZONE	$ 110,092
8	Baltimore Gas and Electric Company		Fixed Amounts - Dollars - Annual	$	6,626,154	Various	6,626,154	68.8874%	Demand - DOMZONE	4,564,583
9	Delmarva Power & Light Company		Fixed Amounts - Dollars - Annual	$	37,826	Various	37,826	68.8874%	Demand - DOMZONE	26,057
10	Mid-Atlantic Interstate Transmission, LLC		Fixed Amounts - Dollars - Annual	$	2,402,637	Various	2,402,637	68.8874%	Demand - DOMZONE	1,655,113
11	Potomac Electric Power Company		Fixed Amounts - Dollars - Annual	$	832,704	Various	832,704	68.8874%	Demand - DOMZONE	573,628
12	PPL Electric Utilities Corporation		Fixed Amounts - Dollars - Annual	$	5,065,248	Various	5,065,248	68.8874%	Demand - DOMZONE	3,489,316
13	PECO Energy Company		Fixed Amounts - Dollars - Annual	$	417,433	Various	417,433	68.8874%	Demand - DOMZONE	287,559
14	Public Service Electric and Gas Company		Fixed Amounts - Dollars - Annual	$	9,696,333	Various	9,696,333	68.8874%	Demand - DOMZONE	6,679,548
15	Trans-Allegheny Interstate Line Company (TrAILCo)		Fixed Amounts - Dollars - Annual	$	59,311,328	Various	59,311,328	68.8874%	Demand - DOMZONE	40,858,009
16	Commonwealth Edison Company		Fixed Amounts - Dollars - Annual	$	106,733	Various	106,733	68.8874%	Demand - DOMZONE	73,525
17	AEP Operating Companies		Fixed Amounts - Dollars - Annual	$	7,335,208	Various	7,335,208	68.8874%	Demand - DOMZONE	5,053,032
18	Duquesne Light Company		Fixed Amounts - Dollars - Annual	$	91,994	Various	91,994	68.8874%	Demand - DOMZONE	63,372
19	Virginia Electric and Power Company		Fixed Amounts - Dollars - Annual	$	257,300,332	Various	257,300,332	68.8874%	Demand - DOMZONE	177,247,411
20	American Transmission Systems, Inc.		Fixed Amounts - Dollars - Annual	$	31,385	Various	31,385	68.8874%	Demand - DOMZONE	21,620
21	Transource Maryland, LLC		Fixed Amounts - Dollars - Annual	$	788,171	Various	788,171	68.8874%	Demand - DOMZONE	542,950
22	Transource Pennsylvania, LLC		Fixed Amounts - Dollars - Annual	$	4,981,141	Various	4,981,141	68.8874%	Demand - DOMZONE	3,431,377
23	Northern Indiana Public Service Company		Fixed Amounts - Dollars - Annual	$	271,674	Various	271,674	68.8874%	Demand - DOMZONE	187,149
24	South FirstEnergy Operating Companies		Fixed Amounts - Dollars - Annual	$	1,403,886	Various	1,403,886	68.8874%	Demand - DOMZONE	967,100
25	**Total Transmission Enhancement Charges**				356,860,002		$ 356,860,002			$ 245,831,441
26	**Transmission Enhancement Credits (Schedule 12 - PJM OATT)**	(b)								
27	Dominion Energy Virginia		Fixed Amounts - Dollars - Annualized	$	(467,313,528)	Various	$ (467,313,528)	68.8874%	Demand - DOMZONE	$ (321,919,961)
28	**Other**									
29	Generation Deactivation Charges		Fixed Amounts - Dollars - Historical	$	-		-	85.2236%	Demand - DOMLSE	-
30	Generation Deactivation Credits		Fixed Amounts - Dollars - Historical	$	-		-	85.2236%	Demand - DOMLSE	-
31	Dominion Energy Virginia Settlement EL05-121-009	(b)	Fixed Amounts - Dollars - Historical	$	4,286,367		4,286,367	68.8874%	Demand - DOMZONE	2,952,765
32	**Total Transmission Enhancement**						$ (106,167,159)			$ (73,135,755)
33	**PJM Administrative Charges**									
34	9-1 Control Area		Rate Year Projected Transmission Use	MWh	109,753,962	0.221904	$ 24,354,843	82.3977%	Energy - DOMLSE	$ 20,067,839
35	9-2 Financial Transmission Rights		Quantity of MWh of All FTR	MWh	103,967,143	0.001688	175,497	82.3977%	Energy - DOMLSE	144,605
36	9-2 Financial Transmission Rights		FTR Bid Options x 5	Hours	-	0.000570	-	82.3977%	Energy - DOMLSE	-
37	9-2 Financial Transmission Rights		FTR Bid Obligations	Hours	-	0.000570	-	82.3977%	Energy - DOMLSE	-
38	**Total PJM Administrative Charges**						$ 24,530,340			$ 20,212,445
39	**Demand Response Programs Approved by FERC**									
40	Economic/Emergency Load Response Programs		Historical/Assigned	$	1,124,738		$ 1,124,738	82.3977%	Energy - DOMLSE	$ 926,758
41	**Total Demand Response Programs Approved by FERC**						$ 1,124,738			$ 926,758
42	**Total Revenue Requirement**						$ 1,297,708,251			$ 1,122,913,922

Notes:

(a) See Formula Schedule 2, page 2 for Source Location.
(b) Billed at Dominion Zone level.

Virginia Electric and Power Company
Subsection A 4 Costs
Cost of Service - Source Location

Line No.	Description	Billing Determinant	Item Location	Rate		Item Location	Virginia Juris. Allocator	Item Location
1	**Network Integration Transmission Service (NITS)**	18,276.3	PJM Website	75,876.81		PJM Website/Markets & Operations/Billing, Settlements/Formula Rates	85.2236%	Formula Schedule 8; pg. 1; line 3
2	Firm Point-to-Point Transmission Service	(15,789,493)	Formula Schedule 3; line 1			Information obtained per historical invoices (PJM)	85.2236%	Formula Schedule 8; pg. 1; line 3
3	Non-Firm Point-to-Point Transmission Service	(2,389,344)	Formula Schedule 3; line 2			Information obtained per historical invoices (PJM)	85.2236%	Formula Schedule 8; pg. 1; line 3
4	Underground Transmission Service (Docket EL10-49)	9,651,813	Formula Schedule 3; line 3			Formula Schedule 3; line 3	88.7647%	Formula Schedule 8; pg. 1; line 15
5	**Net Network Integration Transmission Service (NITS)**							
6	**Transmission Enhancement Charges (Schedule 12 - PJM OATT)**							
7	Atlantic City Electric Company	159,815	Formula Schedule 4; line 2		(a)	Formula Schedule 4; line 2	68.8874%	Formula Schedule 8; pg. 1; line 6
8	Baltimore Gas and Electric Company	6,626,154	Formula Schedule 4; line 13		(a)	Formula Schedule 4; line 13	68.8874%	Formula Schedule 8; pg. 1; line 6
9	Delmarva Power & Light Company	37,826	Formula Schedule 4; line 16		(a)	Formula Schedule 4; line 16	68.8874%	Formula Schedule 8; pg. 1; line 6
10	Mid-Atlantic Interstate Transmission, LLC	2,402,637	Formula Schedule 4; line 30		(a)	Formula Schedule 4; line 30	68.8874%	Formula Schedule 8; pg. 1; line 6
11	Potomac Electric Power Company	832,704	Formula Schedule 4; line 39		(a)	Formula Schedule 4; line 39	68.8874%	Formula Schedule 8; pg. 1; line 6
12	PPL Electric Utilities Corporation	5,065,248	Formula Schedule 4; line 49		(a)	Formula Schedule 4; line 49	68.8874%	Formula Schedule 8; pg. 1; line 6
13	PECO Energy Company	417,433	Formula Schedule 4; line 56		(a)	Formula Schedule 4; line 56	68.8874%	Formula Schedule 8; pg. 1; line 6
14	Public Service Electric and Gas Company	9,696,333	Formula Schedule 4; line 74		(a)	Formula Schedule 4; line 74	68.8874%	Formula Schedule 8; pg. 1; line 6
15	Trans-Allegheny Interstate Line Company (TrAILCo)	59,311,328	Formula Schedule 4; line 100		(a)	Formula Schedule 4; line 100	68.8874%	Formula Schedule 8; pg. 1; line 6
16	Commonwealth Edison Company	106,733	Formula Schedule 4; line 103		(a)	Formula Schedule 4; line 103	68.8874%	Formula Schedule 8; pg. 1; line 6
17	AEP Operating Companies	7,335,208	Formula Schedule 4; line 130		(a)	Formula Schedule 4; line 130	68.8874%	Formula Schedule 8; pg. 1; line 6
18	Duquesne Light Company	91,994	Formula Schedule 4; line 132		(a)	Formula Schedule 4; line 132	68.8874%	Formula Schedule 8; pg. 1; line 6
19	Virginia Electric and Power Company	257,300,332	Formula Schedule 4; line 255		(a)	Formula Schedule 4; line 255	68.8874%	Formula Schedule 8; pg. 1; line 6
20	American Transmission Systems, Inc.	31,385	Formula Schedule 4; line 257		(a)	Formula Schedule 4; line 257	68.8874%	Formula Schedule 8; pg. 1; line 6
21	Transource Maryland, LLC	788,171	Formula Schedule 4; line 260		(a)	Formula Schedule 4; line 260	68.8874%	Formula Schedule 8; pg. 1; line 6
22	Transource Pennsylvania, LLC	4,981,141	Formula Schedule 4; line 263		(a)	Formula Schedule 4; line 263	68.8874%	Formula Schedule 8; pg. 1; line 6
23	Northern Indiana Public Service Company	271,674	Formula Schedule 4; line 268		(a)	Formula Schedule 4; line 268	68.8874%	Formula Schedule 8; pg. 1; line 6
24	South FirstEnergy Operating Companies	1,403,886	Formula Schedule 4; line 281		(a)	Formula Schedule 4; line 281	68.8874%	Formula Schedule 8; pg. 1; line 6
25	**Total Transmission Enhancement Charges**	356,860,002	Formula Schedule 4; line 283		(a)	Formula Schedule 4; line 283		
26	**Transmission Enhancement Credits (Schedule 12 - PJM OATT)**							
27	Dominion Energy Virginia	(467,313,528)	Formula Schedule 5; line 123		(a)	Formula Schedule 5; line 123	68.8874%	Formula Schedule 8; pg. 1; line 6
28	**Other**							
29	Generation Deactivation Charges	-	Formula Schedule 4a; line 1			None expected during the rate year.	85.2236%	Formula Schedule 8; pg. 1; line 3
30	Generation Deactivation Credits	-	Formula Schedule 4a; line 2			None expected during the rate year.	85.2236%	Formula Schedule 8; pg. 1; line 3
31	Dominion Energy Virginia Settlement EL05-121-009	4,286,367	Formula Schedule 4a; line 3			Formula Schedule 4a; line 3	68.8874%	Formula Schedule 8; pg. 1; line 6
32	**Total Transmission Enhancement**							
33	**PJM Administrative Charges**							
34	9-1 Control Area	109,753,962	Formula Schedule 6; line 2	0.221904	(b)	PJM Website; "OATT - Schedule 9"; plus any posted quarterly adjustments	82.3977%	Formula Schedule 8; pg. 1; line 9
35	9-2 Financial Transmission Rights	103,967,143	Formula Schedule 6; line 3	0.001688	(b)	PJM Website; "OATT - Schedule 9"; plus any posted quarterly adjustments	82.3977%	Formula Schedule 8; pg. 1; line 9
36	9-2 Financial Transmission Rights	-	Formula Schedule 6; line 4	0.000570	(b)	PJM Website; "OATT - Schedule 9"; plus any posted quarterly adjustments	82.3977%	Formula Schedule 8; pg. 1; line 9
37	9-2 Financial Transmission Rights	-	Formula Schedule 6; line 5	0.000570	(b)	PJM Website; "OATT - Schedule 9"; plus any posted quarterly adjustments	82.3977%	Formula Schedule 8; pg. 1; line 9
38	**Total PJM Administrative Charges**							
39	**Demand Response Programs Approved by FERC**							
40	Economic/Emergency Load Response Programs	1,124,738	Formula Schedule 7; line 1			Information obtained per historical invoices (PJM)	82.3977%	Formula Schedule 8; pg. 1; line 9
41	**Total Demand Response Programs Approved by FERC**							

Notes:

(a) The billing determinant is the amount of revenue requirement listed for each transmission enhancement project allocated by PJM to the Dominion Zone. The revenue requirement assigned to each project is listed in the appropriate formula rate for each transmission owner and can be located per: PJM.com / Markets & Operations / Billings, Settlements & Credit / Formula Rates. Enhancement projects for each transmission owner and the applicable demand allocation ratios for those transmission owners charged are listed within PJM OATT-Schedule 12 and can be located at: PJM.com / Library / Governing Documents - OATT.

(b) The rates listed are per the PJM website effective for January 2025, posted 2/6/2025, and can be located at PJM.com / Committees & Groups / Committees / Finance Committee / PJM Administrative Cost Rates / 2025 Schedule 9 Rates.

Virginia Electric and Power Company
Subsection A 4 Costs
Derivation of Point-to-Point Transmission Service Revenue Credits and Underground Transmission Service Charges

Line No.			Jan-25	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
1	Firm Point-to-Point Transmission Service	(a)	$ (2,749,180)	$ (1,088,653)	$ (965,185)	$ (964,410)	$ (992,540)	$ (1,236,172)	$ (1,449,514)	$ (1,296,487)	$ (1,044,165)	$ (1,195,880)	$ (1,227,631)	$ (1,579,676)	**$ (15,789,493)**
2	Non-Firm Point-to-Point Transmission Service	(a)	$ (304,509)	$ (181,479)	$ (190,838)	$ (147,752)	$ (150,749)	$ (222,041)	$ (170,216)	$ (186,076)	$ (192,082)	$ (167,717)	$ (186,202)	$ (289,683)	**$ (2,389,344)**

			RATE YEAR												
			Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Total
3	Underground Transmission Service (Docket EL10-49)	(b)	$ 793,300	$ 819,743	$ 793,300	$ 819,743	$ 819,743	$ 740,413	$ 819,743	$ 793,300	$ 819,743	$ 793,300	$ 819,743	$ 819,743	**$ 9,651,813**

Notes:
(a) Information obtained per historical PJM invoices.
(b) Dominion Energy Virginia calculated monthly amount based on total incremental undergrounding costs revenue requirement included in 2025 NITS formula rate projection, ATT 10, DOMLSE portion.

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Line No.	PJM Transmission Owner (a)		Project Revenue Requirement (a)	Dom Zone Ratio (a)		Dom Zone Charge		Dom Zone Total
1	**Atlantic Electric Company**							
2	PJM Upgrade ID - b0210.A	$	1,125,456	14.20%	$	159,815	$	159,815
3	**Baltimore Gas and Electric Company**							
4	PJM Upgrade ID - b0298	$	6,115,030	11.54%	$	705,674		
5	PJM Upgrade ID - b1016	$	11,689,097	16.10%	$	1,881,945		
6	PJM Upgrade ID - b1251	$	3,138,609	18.76%	$	588,803		
7	PJM Upgrade ID - b1251.1	$	3,937,008	18.76%	$	738,583		
8	PJM Upgrade ID - b2766.1	$	588,921	14.20%	$	83,627		
9	PJM Upgrade ID - b2766.1_dfax	$	588,921	39.76%	$	234,155		
10	PJM Upgrade ID - b2992.3	$	47,508	27.05%	$	12,851		
11	PJM Upgrade ID - b2992.4	$	1,618,473	27.05%	$	437,797		
12	PJM Upgrade ID - b2992.1	$	3,133,309	27.05%	$	847,560		
13	PJM Upgrade ID - b2992.2	$	4,048,650	27.05%	$	1,095,160	$	6,626,154
14	**Delmarva Power & Light Company**							
15	PJM Upgrade ID - b0272.1	$	10,997	14.20%	$	1,562		
16	PJM Upgrade ID - b0751	$	255,381	14.20%	$	36,264	$	37,826
17	**Jersey Central Power & Light (Transmission) ***							
18	**Mid-Atlantic Interstate Transmission, LLC**							
19	PJM Upgrade ID - b0549	$	292,181	14.20%	$	41,490		
20	PJM Upgrade ID - b2006.1.1	$	319,214	14.20%	$	45,328		
21	PJM Upgrade ID - b2452	$	1,398,386	36.92%	$	516,284		
22	PJM Upgrade ID - b2452.1	$	327,091	36.92%	$	120,762		
23	PJM Upgrade ID - b2743.2	$	(166,596)	39.95%	$	(66,555)		
24	PJM Upgrade ID - b2743.3	$	(57,114)	39.95%	$	(22,817)		
25	PJM Upgrade ID - b2743.4	$	4,214	39.95%	$	1,683		
26	PJM Upgrade ID - b2688.1	$	2,519,692	44.85%	$	1,130,082		
27	PJM Upgrade ID - b0284.3	$	2,486	14.20%	$	353		
28	PJM Upgrade ID - b0369	$	121,799	14.20%	$	17,295		
29	PJM Upgrade ID - b3145	$	1,175,677	52.77%	$	620,405		
30	PJM Upgrade ID - b2752.4	$	(4,189)	39.95%	$	(1,674)	$	2,402,637
31	**Potomac Electric Power Company**							
32	PJM Upgrade ID - b0512.7	$	99,687	14.20%	$	14,156		
33	PJM Upgrade ID - b0512.7_dfax	$	99,687	0.30%	$	299		
34	PJM Upgrade ID - b0512.9	$	99,687	14.20%	$	14,156		
35	PJM Upgrade ID - b0512.9_dfax	$	99,687	0.30%	$	299		
36	PJM Upgrade ID - b0512.12	$	100,889	14.20%	$	14,326		
37	PJM Upgrade ID - b0512.12_dfax	$	100,889	0.30%	$	303		
38	PJM Upgrade ID - b0496	$	2,143,380	10.91%	$	233,843		
39	PJM Upgrade ID - b0288	$	3,266,607	17.00%	$	555,323	$	832,704
40	**PPL Electric Utilities Corporation**							
41	PJM Upgrade ID - b0487	$	30,920,357	14.20%	$	4,390,691		
42	PJM Upgrade ID - b0171.2	$	3,421	14.20%	$	486		
43	PJM Upgrade ID - b0172.1	$	2,453	14.20%	$	348		
44	PJM Upgrade ID - b0284.2	$	4,977	14.20%	$	707		
45	PJM Upgrade ID - b2006.1	$	2,006,359	14.20%	$	284,903		
46	PJM Upgrade ID - b2237	$	725,831	14.20%	$	103,068		
47	PJM Upgrade ID - b2716	$	681,163	14.20%	$	96,725		
48	PJM Upgrade ID - b2824	$	830,329	14.20%	$	117,907		
49	PJM Upgrade ID - b3698	$	2,166,594	3.25%	$	70,414	$	5,065,248

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Line No.	PJM Transmission Owner (a)		Project Revenue Requirement (a)	Dom Zone Ratio (a)	Dom Zone Charge	Dom Zone Total
50	**PECO Energy Company**					
51	PJM Upgrade ID -	b0269	$ 2,003,297	14.20%	$ 284,468	
52	PJM Upgrade ID -	b0269.6	$ 208,373	14.20%	$ 29,589	
53	PJM Upgrade ID -	b0171.1	$ 281,136	14.20%	$ 39,921	
54	PJM Upgrade ID -	b0287	$ 321,723	14.20%	$ 45,685	
55	PJM Upgrade ID -	b2694	$ 1,873,570	0.35%	$ 6,557	
56	PJM Upgrade ID -	b2766.2	$ 78,965	14.20%	$ 11,213	$ 417,433
57	**Public Service Electric and Gas Company**					
58	PJM Upgrade ID -	b0498	$ 1,013,245	14.20%	$ 143,881	
59	PJM Upgrade ID -	b0489	$ 34,225,122	14.20%	$ 4,859,967	
60	PJM Upgrade ID -	b0172.2	$ 1,018	14.20%	$ 145	
61	PJM Upgrade ID -	b0489.5-9	$ 10,491	14.20%	$ 1,490	
62	PJM Upgrade ID -	b1410-1415	$ 675,112	14.20%	$ 95,866	
63	PJM Upgrade ID -	b0290	$ 3,182,838	14.20%	$ 451,963	
64	PJM Upgrade ID -	b2436.21	$ 3,110,677	14.20%	$ 441,716	
65	PJM Upgrade ID -	b2436.22	$ 2,299,962	14.20%	$ 326,595	
66	PJM Upgrade ID -	b2436.81	$ 2,595,298	14.20%	$ 368,532	
67	PJM Upgrade ID -	b2436.83	$ 2,595,298	14.20%	$ 368,532	
68	PJM Upgrade ID -	b2436.90	$ 1,439,564	14.20%	$ 204,418	
69	PJM Upgrade ID -	b2436.10	$ 8,242,073	14.20%	$ 1,170,374	
70	PJM Upgrade ID -	b2436.84	$ 2,517,763	14.20%	$ 357,522	
71	PJM Upgrade ID -	b2436.85	$ 2,517,763	14.20%	$ 357,522	
72	PJM Upgrade ID -	b0376	$ 50,325	14.20%	$ 7,146	
73	PJM Upgrade ID -	b2702	$ 1,070,346	14.20%	$ 151,989	
74	PJM Upgrade ID -	b2633.4	$ 2,737,138	14.20%	$ 388,674	$ 9,696,333
75	**Trans-Allegheny Interstate Line Company (TrAILCo)**					
76	PJM Upgrade ID -	b0216	$ 2,801,985	14.20%	$ 397,882	
77	PJM Upgrade ID -	b0216_dfax	$ 2,801,985	50.23%	$ 1,407,437	
78	PJM Upgrade ID -	b0218	$ 2,759,374	13.81%	$ 381,070	
79	PJM Upgrade ID -	b0328.1; b0328.2; b0347 (.1; .2; .3; .4)	$ 67,330,115	14.20%	$ 9,560,876	
80	PJM Upgrade ID -	b0328.2_dfax	$ 3,378,625	80.60%	$ 2,723,172	
81	PJM Upgrade ID -	b0347.1_dfax	$ 15,706,769	44.37%	$ 6,969,093	
82	PJM Upgrade ID -	b0347.2_dfax	$ 42,316,977	63.32%	$ 26,795,110	
83	PJM Upgrade ID -	b0347.3_dfax	$ 4,358,278	44.37%	$ 1,933,768	
84	PJM Upgrade ID -	b0347.4_dfax	$ 1,569,465	63.32%	$ 993,785	
85	PJM Upgrade ID -	b0230	$ 894,107	11.75%	$ 105,058	
86	PJM Upgrade ID -	b0559	$ 357,682	14.20%	$ 50,791	
87	PJM Upgrade ID -	b0559_dfax	$ 357,682	63.32%	$ 226,484	
88	PJM Upgrade ID -	b0229	$ 1,066,571	14.50%	$ 154,653	
89	PJM Upgrade ID -	b0495	$ 2,209,474	14.20%	$ 313,745	
90	PJM Upgrade ID -	b0495_dfax	$ 2,209,474	81.30%	$ 1,796,302	
91	PJM Upgrade ID -	b0343	$ 603,663	28.86%	$ 174,217	
92	PJM Upgrade ID -	b0344	$ 586,833	28.82%	$ 169,125	
93	PJM Upgrade ID -	b0345	$ 634,379	28.83%	$ 182,891	
94	PJM Upgrade ID -	b1803	$ 284,228	14.20%	$ 40,360	
95	PJM Upgrade ID -	b1803_dfax	$ 284,228	67.11%	$ 190,745	
96	PJM Upgrade ID -	b1800	$ 2,786,357	14.20%	$ 395,663	
97	PJM Upgrade ID -	b1800_dfax	$ 2,786,357	39.46%	$ 1,099,497	
98	PJM Upgrade ID -	b1804	$ 3,306,118	14.20%	$ 469,469	
99	PJM Upgrade ID -	b1804_dfax	$ 3,306,118	63.32%	$ 2,093,434	
100	PJM Upgrade ID -	b1801	$ 4,611,816	14.89%	$ 686,699	$ 59,311,328
101	**Commonwealth Edison Company**					
102	PJM Upgrade ID -	b2141	$ 26,170,965	0.16%	$ 41,874	
103	PJM Upgrade ID -	b2692.1-b2692.2	$ 1,259,404	5.15%	$ 64,859	$ 106,733

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Line No.	PJM Transmission Owner (a)	Project Revenue Requirement (a)	Dom Zone Ratio (a)	Dom Zone Charge	Dom Zone Total
104	**AEP Operating Companies and AEP Transmission Companies**				
105	PJM Upgrade ID - b0504	$ 299,033	14.20%	$ 42,463	
106	PJM Upgrade ID - b1465.2	$ 765,761	14.20%	$ 108,738	
107	PJM Upgrade ID - b1465.4	$ 318,780	14.20%	$ 45,267	
108	PJM Upgrade ID - b1465.3	$ 1,089,502	14.20%	$ 154,709	
109	PJM Upgrade ID - b1712.2	$ 233,343	75.30%	$ 175,707	
110	PJM Upgrade ID - b1659.14	$ 3,407,295	14.20%	$ 483,836	
111	PJM Upgrade ID - b1659.14_dfax	$ 3,407,295	27.57%	$ 939,391	
112	PJM Upgrade ID - b1661	$ 109,044	14.20%	$ 15,484	
113	PJM Upgrade ID - b2017	$ 8,984,709	6.19%	$ 556,153	
114	PJM Upgrade ID - b1962	$ 1,153,645	14.20%	$ 163,818	
115	PJM Upgrade ID - b1948	$ 5,728,736	13.97%	$ 800,304	
116	PJM Upgrade ID - b1660	$ 178,934	14.20%	$ 25,409	
117	PJM Upgrade ID - b1660.1	$ 1,569,155	14.20%	$ 222,820	
118	PJM Upgrade ID - b1663.2	$ 280,963	14.20%	$ 39,897	
119	PJM Upgrade ID - b1797.1	$ 3,168,301	14.20%	$ 449,899	
120	PJM Upgrade ID - b1797.1_dfax	$ 3,168,301	51.47%	$ 1,630,724	
121	PJM Upgrade ID - b1659.13	$ 2,685,487	14.20%	$ 381,339	
122	PJM Upgrade ID - b1712.1	$ 26,402	75.30%	$ 19,881	
123	PJM Upgrade ID - b1465.1	$ 3,534,198	3.89%	$ 137,480	
124	PJM Upgrade ID - b2230	$ 688,011	14.20%	$ 97,697	
125	PJM Upgrade ID - b2423	$ 1,067,362	14.20%	$ 151,565	
126	PJM Upgrade ID - b2687.1	$ 3,868,871	14.20%	$ 549,380	
127	PJM Upgrade ID - b2687.2	$ 510,659	14.20%	$ 72,514	
128	PJM Upgrade ID - b1465.5	$ 479,382	14.20%	$ 68,072	
129	PJM Upgrade ID - b3800.121	$ 3,481	14.20%	$ 494	
130	PJM Upgrade ID - b3800.121_dfax	$ 3,481	62.25%	$ 2,167	$ 7,335,208
131	**Duquesne Light Company**				
132	PJM Upgrade ID - b2689.1-2	$ 1,044,196	8.81%	$ 91,994	$ 91,994
133	**Virginia Electric and Power Company**				
134	PJM Upgrade ID - b0217	$ 97,506	14.20%	$ 13,846	
135	PJM Upgrade ID - b0217_dfax	$ 97,506	67.11%	$ 65,436	
136	PJM Upgrade ID - b0222	$ 79,233	14.20%	$ 11,251	
137	PJM Upgrade ID - b0222_dfax	$ 79,233	80.60%	$ 63,862	
138	PJM Upgrade ID - b0226	$ 799,190	85.73%	$ 685,146	
139	PJM Upgrade ID - b0403	$ 875,894	83.94%	$ 735,226	
140	PJM Upgrade ID - b0328.1	$ 12,069,157	14.20%	$ 1,713,820	
141	PJM Upgrade ID - b0328.1_dfax	$ 12,069,157	80.60%	$ 9,727,741	
142	PJM Upgrade ID - b0328.3	$ 739,621	14.20%	$ 105,026	
143	PJM Upgrade ID - b0328.3_dfax	$ 739,621	63.32%	$ 468,328	
144	PJM Upgrade ID - b0328.4	$ 166,877	14.20%	$ 23,696	
145	PJM Upgrade ID - b0328.4_dfax	$ 166,877	80.60%	$ 134,503	
146	PJM Upgrade ID - b0768	$ 2,509,762	100.00%	$ 2,509,762	
147	PJM Upgrade ID - b0337	$ 642,630	100.00%	$ 642,630	
148	PJM Upgrade ID - b0311	$ 324,691	100.00%	$ 324,691	
149	PJM Upgrade ID - b0231	$ 1,111,749	14.20%	$ 157,868	
150	PJM Upgrade ID - b0231_dfax	$ 1,111,749	100.00%	$ 1,111,749	
151	PJM Upgrade ID - b0456	$ 470,472	40.08%	$ 188,565	
152	PJM Upgrade ID - b0227	$ 2,029,770	67.38%	$ 1,367,659	
153	PJM Upgrade ID - b0455	$ 328,533	50.82%	$ 166,961	
154	PJM Upgrade ID - b0453.1	$ 153,400	92.75%	$ 142,279	
155	PJM Upgrade ID - b0453.2	$ 1,466,647	92.75%	$ 1,360,315	
156	PJM Upgrade ID - b0453.3	$ 341,502	92.75%	$ 316,743	
157	PJM Upgrade ID - b0837	$ 37,447	14.20%	$ 5,317	
158	PJM Upgrade ID - b0837_dfax	$ 37,447	100.00%	$ 37,447	

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Line No.	PJM Transmission Owner (a)		Project Revenue Requirement (a)	Dom Zone Ratio (a)	Dom Zone Charge	Dom Zone Total
159	PJM Upgrade ID -	b0327	$ 608,915	76.18%	$ 463,871	
160	PJM Upgrade ID -	b0329.2A	$ 4,352,698	100.00%	$ 4,352,698	
161	PJM Upgrade ID -	b0329.2B	$ 8,783,270	14.20%	$ 1,247,224	
162	PJM Upgrade ID -	b0329.2B_dfax	$ 8,783,270	100.00%	$ 8,783,270	
163	PJM Upgrade ID -	b0467.2	$ 556,258	0.00%	$ -	
164	PJM Upgrade ID -	b1507	$ 17,614,308	14.20%	$ 2,501,232	
165	PJM Upgrade ID -	b1507_dfax	$ 17,614,308	67.11%	$ 11,820,962	
166	PJM Upgrade ID -	b0457	$ 5,532	14.20%	$ 785	
167	PJM Upgrade ID -	b0457_dfax	$ 5,532	85.52%	$ 4,731	
168	PJM Upgrade ID -	b0784	$ 3,836	14.20%	$ 545	
169	PJM Upgrade ID -	b0784_dfax	$ 3,836	92.39%	$ 3,544	
170	PJM Upgrade ID -	b1224	$ 1,536,776	78.21%	$ 1,201,912	
171	PJM Upgrade ID -	b1508.3	$ 126,710	62.95%	$ 79,764	
172	PJM Upgrade ID -	b1647	$ 848	14.20%	$ 120	
173	PJM Upgrade ID -	b1647_dfax	$ 848	100.00%	$ 848	
174	PJM Upgrade ID -	b1648	$ 848	14.20%	$ 120	
175	PJM Upgrade ID -	b1648_dfax	$ 848	100.00%	$ 848	
176	PJM Upgrade ID -	b1649	$ 44,767	14.20%	$ 6,357	
177	PJM Upgrade ID -	b1649_dfax	$ 44,767	100.00%	$ 44,767	
178	PJM Upgrade ID -	b1650	$ 44,767	14.20%	$ 6,357	
179	PJM Upgrade ID -	b1650_dfax	$ 44,767	100.00%	$ 44,767	
180	PJM Upgrade ID -	b1188.6	$ 1,817,192	75.58%	$ 1,373,434	
181	PJM Upgrade ID -	b1188	$ 79,093	14.20%	$ 11,231	
182	PJM Upgrade ID -	b1188_dfax	$ 79,093	100.00%	$ 79,093	
183	PJM Upgrade ID -	b1321	$ 4,213,920	97.96%	$ 4,127,956	
184	PJM Upgrade ID -	b0756.1	$ 220,452	14.20%	$ 31,304	
185	PJM Upgrade ID -	b0756.1_dfax	$ 220,452	100.00%	$ 220,452	
186	PJM Upgrade ID -	b1797	$ 979,761	14.20%	$ 139,126	
187	PJM Upgrade ID -	b1797_dfax	$ 979,761	51.47%	$ 504,283	
188	PJM Upgrade ID -	b1799	$ 1,421,226	14.20%	$ 201,814	
189	PJM Upgrade ID -	b1799_dfax	$ 1,421,226	89.13%	$ 1,266,739	
190	PJM Upgrade ID -	b1798	$ 6,016,977	14.20%	$ 854,411	
191	PJM Upgrade ID -	b1798_dfax	$ 6,016,977	80.60%	$ 4,849,684	
192	PJM Upgrade ID -	b1805	$ 2,004,807	14.20%	$ 284,683	
193	PJM Upgrade ID -	b1805_dfax	$ 2,004,807	44.37%	$ 889,533	
194	PJM Upgrade ID -	b1508.1	$ 7,110,052	62.95%	$ 4,475,778	
195	PJM Upgrade ID -	b1508.2	$ 1,302,368	62.95%	$ 819,841	
196	PJM Upgrade ID -	b2053	$ 4,781,575	0.00%	$ -	
197	PJM Upgrade ID -	b1906.1	$ 557,901	14.20%	$ 79,222	
198	PJM Upgrade ID -	b1906.1_dfax	$ 557,901	100.00%	$ 557,901	
199	PJM Upgrade ID -	b1908	$ 7,080,043	14.20%	$ 1,005,366	
200	PJM Upgrade ID -	b1908_dfax	$ 7,080,043	85.52%	$ 6,054,853	
201	PJM Upgrade ID -	b1905.2	$ 101,956	14.20%	$ 14,478	
202	PJM Upgrade ID -	b1905.2_dfax	$ 101,956	100.00%	$ 101,956	
203	PJM Upgrade ID -	b1328	$ 434,306	92.94%	$ 403,644	
204	PJM Upgrade ID -	b1698	$ 2,574,863	59.38%	$ 1,528,954	
205	PJM Upgrade ID -	b1907	$ 2,093,803	81.79%	$ 1,712,522	
206	PJM Upgrade ID -	b1909	$ 380,925	81.90%	$ 311,977	
207	PJM Upgrade ID -	b1912	$ 11,220,895	99.54%	$ 11,169,279	
208	PJM Upgrade ID -	b1701	$ 363,428	63.30%	$ 230,050	
209	PJM Upgrade ID -	b1791	$ 287,743	78.38%	$ 225,533	
210	PJM Upgrade ID -	b1694	$ 2,639,628	14.20%	$ 374,827	
211	PJM Upgrade ID -	b1694_dfax	$ 2,639,628	74.23%	$ 1,959,396	
212	PJM Upgrade ID -	b1911	$ 2,483,729	74.12%	$ 1,840,940	
213	PJM Upgrade ID -	b2471	$ 440,938	14.20%	$ 62,613	
214	PJM Upgrade ID -	b2471_dfax	$ 440,938	100.00%	$ 440,938	
215	PJM Upgrade ID -	b1905.1	$ 15,026,848	14.20%	$ 2,133,812	
216	PJM Upgrade ID -	b1905.1_dfax	$ 15,026,848	100.00%	$ 15,026,848	
217	PJM Upgrade ID -	b1905.5	$ 600,834	99.84%	$ 599,872	
218	PJM Upgrade ID -	b1696	$ 23,105,243	88.45%	$ 20,436,587	
219	PJM Upgrade ID -	b2373	$ 2,503,691	14.20%	$ 355,524	

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Line No.	PJM Transmission Owner (a)		Project Revenue Requirement (a)	Dom Zone Ratio (a)		Dom Zone Charge		Dom Zone Total
220	PJM Upgrade ID - b2373_dfax	$	2,503,691	50.29%	$	1,259,106		
221	PJM Upgrade ID - b1905.3	$	13,379,730	99.84%	$	13,358,322		
222	PJM Upgrade ID - b1905.4	$	9,912,144	99.84%	$	9,896,285		
223	PJM Upgrade ID - b2744	$	3,318,564	14.20%	$	471,236		
224	PJM Upgrade ID - b2744_dfax	$	3,318,564	96.17%	$	3,191,463		
225	PJM Upgrade ID - b1905.6	$	164,602	99.84%	$	164,339		
226	PJM Upgrade ID - b1905.7	$	12,879	99.84%	$	12,858		
227	PJM Upgrade ID - b1905.9	$	10,290	99.84%	$	10,273		
228	PJM Upgrade ID - b2582	$	5,445,076	14.20%	$	773,201		
229	PJM Upgrade ID - b2582_dfax	$	5,445,076	81.93%	$	4,461,151		
230	PJM Upgrade ID - b2443	$	5,940,893	97.11%	$	5,769,201		
231	PJM Upgrade ID - b2665	$	4,640,397	14.20%	$	658,936		
232	PJM Upgrade ID - b2665_dfax	$	4,640,397	71.52%	$	3,318,812		
233	PJM Upgrade ID - b2758	$	3,423,567	14.20%	$	486,147		
234	PJM Upgrade ID - b2758_dfax	$	3,423,567	100.00%	$	3,423,567		
235	PJM Upgrade ID - b2729	$	1,112,228	35.11%	$	390,503		
236	PJM Upgrade ID - b2928	$	1,911,375	14.20%	$	271,415		
237	PJM Upgrade ID - b2928_dfax	$	1,911,375	100.00%	$	1,911,375		
238	PJM Upgrade ID - b2960.1	$	1,081,703	14.20%	$	153,602		
239	PJM Upgrade ID - b2960.1_dfax	$	1,081,703	88.65%	$	958,929		
240	PJM Upgrade ID - b2960.2	$	1,130,782	14.20%	$	160,571		
241	PJM Upgrade ID - b2960.2_dfax	$	1,130,782	87.48%	$	989,208		
242	PJM Upgrade ID - b2978	$	6,600,387	14.20%	$	937,255		
243	PJM Upgrade ID - b2978_dfax	$	6,600,387	100.00%	$	6,600,387		
244	PJM Upgrade ID - b2759	$	39,732,389	14.20%	$	5,641,999		
245	PJM Upgrade ID - b2759_dfax	$	39,732,389	44.80%	$	17,800,110		
246	PJM Upgrade ID - b3027.1	$	3,101,081	100.00%	$	3,101,081		
247	PJM Upgrade ID - b3019	$	5,940,753	14.20%	$	843,587		
248	PJM Upgrade ID - b3019_dfax	$	5,940,753	89.57%	$	5,321,132		
249	PJM Upgrade ID - b3020	$	2,268,560	14.20%	$	322,136		
250	PJM Upgrade ID - b3020_dfax	$	2,268,560	51.27%	$	1,163,091		
251	PJM Upgrade ID - b3021	$	3,838,281	14.20%	$	545,036		
252	PJM Upgrade ID - b3021_dfax	$	3,838,281	89.94%	$	3,452,150		
253	PJM Upgrade ID - b3702	$	(270,119)	18.99%	$	(51,296)		
254	PJM Upgrade ID - b3718.3	$	19,406,322	14.20%	$	2,755,698		
255	PJM Upgrade ID - b3718.3_dfax	$	19,406,322	89.54%	$	17,376,421	$	257,300,332
256	**American Transmission Systems, Inc.**							
257	PJM Upgrade ID - b2972	$	591,059	5.31%	$	31,385	$	31,385
258	**Transource West Virginia, LLC ***							
259	**Transource Maryland, LLC**							
260	PJM Upgrade ID - b2743.5/b2752.5	$	1,972,893	39.95%	$	788,171	$	788,171
261	**Transource Pennsylvania, LLC**							
262	PJM Upgrade ID - b2743.5/b2743.1/b2752.5/b2752.1	$	12,339,042	39.95%	$	4,929,447		
263	PJM Upgrade ID - b3737.47	$	364,041	14.20%	$	51,694	$	4,981,141
264	**Silver Run Electric, Inc. ***							
265	**Northern Indiana Public Service Company in MISO, Inc.**							
266	PJM Upgrade ID - b2971	$	799,509	15.20%	$	121,525		
267	PJM Upgrade ID - b2973	$	758,112	14.70%	$	111,442		
268	PJM Upgrade ID - b2975	$	889,793	4.35%	$	38,706	$	271,674
269	**Transmission Owners in Midcontinent Indepent System Operator, Inc. (MISO) ***							
270	**The Dayton Power & Light Company ***							

Virginia Electric and Power Company
Subsection A 4 Costs
Calculation of Cost of Service for Transmission Enhancement Charges
2025

Line No.	PJM Transmission Owner (a)		Project Revenue Requirement (a)	Dom Zone Ratio (a)		Dom Zone Charge		Dom Zone Total
271	**South FirstEnergy Operating Companies**							
272	PJM Upgrade ID - b0577	$	-	14.20%	$	-		
273	PJM Upgrade ID - b0238	$	497,095	33.66%	$	167,322		
274	PJM Upgrade ID - b1507.2	$	10,164	14.20%	$	1,443		
275	PJM Upgrade ID - b1507.2_dfax	$	10,164	67.11%	$	6,821		
276	PJM Upgrade ID - b1507.3	$	1,302,519	14.20%	$	184,958		
277	PJM Upgrade ID - b1507.3_dfax	$	1,302,519	67.11%	$	874,120		
278	PJM Upgrade ID - b2688.3	$	86,221	44.85%	$	38,670		
279	PJM Upgrade ID - b0347.17-32	$	167,533	14.20%	$	23,790		
280	PJM Upgrade ID - b0347.17-32_dfax	$	167,533	63.32%	$	106,082		
281	PJM Upgrade ID - b1835	$	1,972	34.46%	$	680	$	1,403,886
282	**Keystone Appalachian Transmmission Company ***							
283	**Total Dominion Energy Virginia Transmission Enhancement Charges**						$	356,860,002

Notes:
(*) No projects allocated to Dominion Energy Virginia.
(a) PJM website, Transmission Enhancement Worksheet dated 2/25/2025.

Virginia Electric and Power Company
Subsection A 4 Costs
Other Transmission Enhancement Charges/Credits

Line No.			Jan-25	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
1	Generation Deactivation Charges	(a)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Generation Deactivation Credits	(a)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			RATE YEAR												
			Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Total
3	Dominion Energy Virginia Settlement EL05-121-009	(b)	$ 1,071,592	$ 1,071,592	$ 1,071,592	$ 1,071,592	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4,286,367**

Notes:
(a) Information obtained per historical PJM invoices. There are no currently known charges or credits scheduled to occur during the rate year September 1, 2025 through August 31, 2026.
(b) Anticipated rate year charges per the Dominion Energy Virginia settlement for FERC Docket No. EL05-121-009 (Schedule 12-C, Appendix C, PJM OATT - Transmission Enhancement Charge Adjustments). Effective through December 31, 2025.

Virginia Electric and Power Company
Subsection A 4 Costs
Transmission Enhancement Credits
2025

Transmission Enhancement Projects Owned by Dominion Energy Virginia

Line No.	PJM Upgrade ID (a)		Annual Revenue Requirement - including incentive (a)	Incentive (b)	Annual Revenue Requirement without incentive
1	PJM Upgrade ID - b0217	$	97,506	$ -	$ 97,506
2	PJM Upgrade ID - b0217_dfax	$	97,506	-	97,506
3	PJM Upgrade ID - b0222	$	79,233	-	79,233
4	PJM Upgrade ID - b0222_dfax	$	79,233	-	79,233
5	PJM Upgrade ID - b0226	$	799,190	-	799,190
6	PJM Upgrade ID - b0403	$	875,894	-	875,894
7	PJM Upgrade ID - b0328.1	$	12,069,157	1,444,891	10,624,266
8	PJM Upgrade ID - b0328.1_dfax	$	12,069,157	-	12,069,157
9	PJM Upgrade ID - b0328.3	$	739,621	87,402	652,219
10	PJM Upgrade ID - b0328.3_dfax	$	739,621	-	739,621
11	PJM Upgrade ID - b0328.4	$	166,877	20,075	146,802
12	PJM Upgrade ID - b0328.4_dfax	$	166,877	-	166,877
13	PJM Upgrade ID - b0768	$	2,509,762	127,134	2,382,628
14	PJM Upgrade ID - b0337	$	642,630	32,049	610,581
15	PJM Upgrade ID - b0311	$	324,691	16,242	308,449
16	PJM Upgrade ID - b0231	$	1,111,749	-	1,111,749
17	PJM Upgrade ID - b0231_dfax	$	1,111,749	-	1,111,749
18	PJM Upgrade ID - b0456	$	470,472	-	470,472
19	PJM Upgrade ID - b0227	$	2,029,770	-	2,029,770
20	PJM Upgrade ID - b0455	$	328,533	-	328,533
21	PJM Upgrade ID - b0453.1	$	153,400	7,732	145,668
22	PJM Upgrade ID - b0453.2	$	1,466,647	74,736	1,391,911
23	PJM Upgrade ID - b0453.3	$	341,502	17,093	324,409
24	PJM Upgrade ID - b0837	$	37,447	-	37,447
25	PJM Upgrade ID - b0837_dfax	$	37,447	-	37,447
26	PJM Upgrade ID - b0327	$	608,915	-	608,915
27	PJM Upgrade ID - b0329.2A	$	4,352,698	261,795	4,090,903
28	PJM Upgrade ID - b0329.2B	$	8,783,270	1,050,083	7,733,187
29	PJM Upgrade ID - b0329.2B_dfax	$	8,783,270	-	8,783,270
30	PJM Upgrade ID - b0467.2	$	556,258	28,179	528,079
31	PJM Upgrade ID - b1507	$	17,614,308	-	17,614,308
32	PJM Upgrade ID - b1507_dfax	$	17,614,308	-	17,614,308
33	PJM Upgrade ID - b0457	$	5,532	-	5,532
34	PJM Upgrade ID - b0457_dfax	$	5,532	-	5,532
35	PJM Upgrade ID - b0784	$	3,836	-	3,836
36	PJM Upgrade ID - b0784_dfax	$	3,836	-	3,836
37	PJM Upgrade ID - b1224	$	1,536,776	-	1,536,776
38	PJM Upgrade ID - b1508.3	$	126,710	-	126,710
39	PJM Upgrade ID - b1647	$	848	-	848
40	PJM Upgrade ID - b1647_dfax	$	848	-	848
41	PJM Upgrade ID - b1648	$	848	-	848
42	PJM Upgrade ID - b1648_dfax	$	848	-	848
43	PJM Upgrade ID - b1649	$	44,767	-	44,767
44	PJM Upgrade ID - b1649_dfax	$	44,767	-	44,767
45	PJM Upgrade ID - b1650	$	44,767	-	44,767
46	PJM Upgrade ID - b1650_dfax	$	44,767	-	44,767
47	PJM Upgrade ID - b1188.6	$	1,817,192	-	1,817,192
48	PJM Upgrade ID - b1188	$	79,093	-	79,093
49	PJM Upgrade ID - b1188_dfax	$	79,093	-	79,093
50	PJM Upgrade ID - b1321	$	4,213,920	-	4,213,920
51	PJM Upgrade ID - b0756.1	$	220,452	-	220,452
52	PJM Upgrade ID - b0756.1_dfax	$	220,452	-	220,452
53	PJM Upgrade ID - b1797	$	979,761	-	979,761
54	PJM Upgrade ID - b1797_dfax	$	979,761	-	979,761
55	PJM Upgrade ID - b1799	$	1,421,226	-	1,421,226
56	PJM Upgrade ID - b1799_dfax	$	1,421,226	-	1,421,226
57	PJM Upgrade ID - b1798	$	6,016,977	-	6,016,977
58	PJM Upgrade ID - b1798_dfax	$	6,016,977	-	6,016,977
59	PJM Upgrade ID - b1805	$	2,004,807	-	2,004,807
60	PJM Upgrade ID - b1805_dfax	$	2,004,807	-	2,004,807
61	PJM Upgrade ID - b1508.1	$	7,110,052	-	7,110,052
62	PJM Upgrade ID - b1508.2	$	1,302,368	-	1,302,368
63	PJM Upgrade ID - b2053	$	4,781,575	-	4,781,575
64	PJM Upgrade ID - b1906.1	$	557,901	-	557,901
65	PJM Upgrade ID - b1906.1_dfax	$	557,901	-	557,901
66	PJM Upgrade ID - b1908	$	7,080,043	-	7,080,043
67	PJM Upgrade ID - b1908_dfax	$	7,080,043	-	7,080,043
68	PJM Upgrade ID - b1905.2	$	101,956	-	101,956

Virginia Electric and Power Company
Subsection A 4 Costs
Transmission Enhancement Credits
2025

Transmission Enhancement Projects Owned by Dominion Energy Virginia

Line No.	PJM Upgrade ID (a)		Annual Revenue Requirement - including incentive (a)		Incentive (b)		Annual Revenue Requirement without incentive
69	PJM Upgrade ID - b1905.2_dfax	$	101,956		-		101,956
70	PJM Upgrade ID - b1328	$	434,306		-		434,306
71	PJM Upgrade ID - b1698	$	2,574,863		-		2,574,863
72	PJM Upgrade ID - b1907	$	2,093,803		-		2,093,803
73	PJM Upgrade ID - b1909	$	380,925		-		380,925
74	PJM Upgrade ID - b1912	$	11,220,895		-		11,220,895
75	PJM Upgrade ID - b1701	$	363,428		-		363,428
76	PJM Upgrade ID - b1791	$	287,743		-		287,743
77	PJM Upgrade ID - b1694	$	2,639,628		-		2,639,628
78	PJM Upgrade ID - b1694_dfax	$	2,639,628		-		2,639,628
79	PJM Upgrade ID - b1911	$	2,483,729		-		2,483,729
80	PJM Upgrade ID - b2471	$	440,938		-		440,938
81	PJM Upgrade ID - b2471_dfax	$	440,938		-		440,938
82	PJM Upgrade ID - b1905.1	$	15,026,848		-		15,026,848
83	PJM Upgrade ID - b1905.1_dfax	$	15,026,848		-		15,026,848
84	PJM Upgrade ID - b1905.5	$	600,834		-		600,834
85	PJM Upgrade ID - b1696	$	23,105,243		-		23,105,243
86	PJM Upgrade ID - b2373	$	2,503,691		-		2,503,691
87	PJM Upgrade ID - b2373_dfax	$	2,503,691		-		2,503,691
88	PJM Upgrade ID - b1905.3	$	13,379,730		-		13,379,730
89	PJM Upgrade ID - b1905.4	$	9,912,144		-		9,912,144
90	PJM Upgrade ID - b2744	$	3,318,564		-		3,318,564
91	PJM Upgrade ID - b2744_dfax	$	3,318,564		-		3,318,564
92	PJM Upgrade ID - b1905.6	$	164,602		-		164,602
93	PJM Upgrade ID - b1905.7	$	12,879		-		12,879
94	PJM Upgrade ID - b1905.9	$	10,290		-		10,290
95	PJM Upgrade ID - b2582	$	5,445,076		-		5,445,076
96	PJM Upgrade ID - b2582_dfax	$	5,445,076		-		5,445,076
97	PJM Upgrade ID - b2443	$	5,940,893		-		5,940,893
98	PJM Upgrade ID - b2665	$	4,640,397		-		4,640,397
99	PJM Upgrade ID - b2665_dfax	$	4,640,397		-		4,640,397
100	PJM Upgrade ID - b2758	$	3,423,567		-		3,423,567
101	PJM Upgrade ID - b2758_dfax	$	3,423,567		-		3,423,567
102	PJM Upgrade ID - b2729	$	1,112,228		-		1,112,228
103	PJM Upgrade ID - b2928	$	1,911,375		-		1,911,375
104	PJM Upgrade ID - b2928_dfax	$	1,911,375		-		1,911,375
105	PJM Upgrade ID - b2960.1	$	1,081,703		-		1,081,703
106	PJM Upgrade ID - b2960.1_dfax	$	1,081,703		-		1,081,703
107	PJM Upgrade ID - b2960.2	$	1,130,782		-		1,130,782
108	PJM Upgrade ID - b2960.2_dfax	$	1,130,782		-		1,130,782
109	PJM Upgrade ID - b2978	$	6,600,387		-		6,600,387
110	PJM Upgrade ID - b2978_dfax	$	6,600,387		-		6,600,387
111	PJM Upgrade ID - b2759	$	39,732,389		-		39,732,389
112	PJM Upgrade ID - b2759_dfax	$	39,732,389		-		39,732,389
113	PJM Upgrade ID - b3027.1	$	3,101,081		-		3,101,081
114	PJM Upgrade ID - b3019	$	5,940,753		-		5,940,753
115	PJM Upgrade ID - b3019_dfax	$	5,940,753		-		5,940,753
116	PJM Upgrade ID - b3020	$	2,268,560		-		2,268,560
117	PJM Upgrade ID - b3020_dfax	$	2,268,560		-		2,268,560
118	PJM Upgrade ID - b3021	$	3,838,281		-		3,838,281
119	PJM Upgrade ID - b3021_dfax	$	3,838,281		-		3,838,281
120	PJM Upgrade ID - b3702	$	(270,119)		-		(270,119)
121	PJM Upgrade ID - b3718.3	$	19,406,322		-		19,406,322
122	PJM Upgrade ID - b3718.3_dfax	$	19,406,322		-		19,406,322
123	**Total**	**$**	**470,480,939**	**$**	**3,167,411**	**$**	**467,313,528**

Notes:
(a) PJM website, Transmission Enhancement Worksheet dated 2/25/2025.
(b) PJM website, most recent posted Virginia Electric & Power Company formula rate.

Virginia Electric and Power Company
Subsection A 4 Costs
Derivation of Billing Determinants for PJM Administrative Costs

Line No.	DOMINION ENERGY VIRGINIA (LSE)		Billing Determinant Basis	Jan-25	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual Amount
1	**PJM Administrative Charges**															
2	9-1 Control Area	(a)	MWh	Based on projected transmission usage for rate year.												**109,753,962**
3	9-2 Financial Transmission Rights	(b)	MWh	9,304,241	7,235,407	7,742,060	7,566,480	7,877,174	9,004,104	9,304,241	9,304,241	9,004,104	9,304,241	9,016,610	9,304,241	**103,967,143**
4	9-2 Financial Transmission Rights - FTR Bid Options x 5	(b)	Hours	-	-	-	-	-	-	-	-	-	-	-	-	**-**
5	9-2 Financial Transmission Rights - FTR Bid Obligations	(b)	Hours	-	-	-	-	-	-	-	-	-	-	-	-	**-**

Notes:
(a) Projection supplied per Integrated Resource Planning - Rate Year 9/1/2025 - 8/31/2026.
(b) Information obtained per historical PJM invoices.

Virginia Electric and Power Company
Subsection A 4 Costs
Derivation of Demand Response Program Costs

Line No.	FERC-Approved Demand Response Program Costs		Jan-25	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
1	Economic/Emergency Load Response	(a)	$ 117,582	$ 14,373	$ 18,526	$ 4,262	$ 41,369	$ 102,966	$ 79,748	$ 119,944	$ 220,433	$ 89,589	$ 228,511	$ 87,435	**$ 1,124,738**

Notes:
(a) Information obtained per historical PJM invoices.

Virginia Electric and Power Company
Subsection A 4 Costs
Calculation of Virginia Jurisdictional Allocators
2024

Line No.			
	Demand - DOMLSE	**MW**	**Allocation Factor**
1	DOMLSE Network Service Peak Load	19,158.363	
2	Virginia Jurisdictional Coincident Peak Demand	16,327.443	
3	Virginia Jurisdictional Allocator (Line 2 / Line 1)		85.2236%
	Demand - DOMZONE	**MW**	
4	Network Service Peak Load	23,701.652	
5	Virginia Jurisdictional Coincident Peak Demand	16,327.443	
6	Virginia Jurisdictional Allocator (Line 5 / Line 4)		68.8874%
	Energy - DOMLSE	**MWh**	
7	DOMLSE Network MWh	98,576,744	
8	Virginia Jurisdiction MWh	81,225,006	
9	Virginia Jurisdictional Allocator (Line 8 / Line 7)		82.3977%
	Demand - DOMLSE Modified for Docket EL10-49 (excludes NC)	**MW**	
10	DOMLSE Coincident Peak Demand	18,394.080	
11	Virginia Jurisdictional Coincident Peak Demand	16,327.443	
12	Virginia Jurisdictional Allocator (line 11 / line 10)		88.7647%

Virginia Electric and Power Company
Subsection A 4 Costs
Calculation of Virginia Jurisdictional Allocators
2023

Line No.			Allocation Factor
	Demand - DOMLSE	**MW**	
1	DOMLSE Network Service Peak Load	18,565.613	
2	Virginia Jurisdictional Coincident Peak Demand	15,834.091	
3	Virginia Jurisdictional Allocator (Line 2 / Line 1)		85.2872%
	Demand - DOMZONE	**MW**	
4	Network Service Peak Load	22,692.384	
5	Virginia Jurisdictional Coincident Peak Demand	15,834.091	
6	Virginia Jurisdictional Allocator (Line 5 / Line 4)		69.7771%
	Energy - DOMLSE	**MWh**	
7	DOMLSE Network MWh	93,579,262	
8	Virginia Jurisdiction MWh	77,021,695	
9	Virginia Jurisdictional Allocator (Line 8 / Line 7)		82.3064%
	Demand - DOMLSE Modified for Docket EL10-49 (excludes NC)	**MW**	
10	DOMLSE Coincident Peak Demand	17,863.725	
11	Virginia Jurisdictional Coincident Peak Demand	15,834.091	
12	Virginia Jurisdictional Allocator (line 11 / line 10)		88.6382%

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Company Exhibit ____
Witness: DMW
Schedule 1

Formula Schedule 9

Virginia Electric and Power Company
Subsection A 4 Costs
Calculation of Monthly True-Up Adjustment
For the Period January 1, 2024 through December 31, 2024

Col. No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Line No.	Description		Source	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total 2024
	Subsection A 4 Costs Per PJM															
1	**Network Integration Transmission Service (NITS)**		PJM Inv	(102,938,146)	(96,371,661)	(103,038,522)	(99,741,091)	(103,065,536)	(99,655,751)	(102,795,671)	(102,800,770)	(99,435,374)	(102,568,680)	(99,137,509)	(102,698,251)	(1,214,246,962)
2	Firm Point to Point Transmission Service		PJM Inv	2,330,233	1,088,653	965,185	964,410	992,540	1,236,172	1,449,514	1,296,487	1,044,165	1,195,880	1,227,631	1,579,676	15,370,546
3	Non-Firm Point to Point Transmission Service		PJM Inv	233,322	181,479	190,838	147,752	150,749	222,041	170,216	186,076	192,082	167,717	186,202	289,683	2,318,157
4	Subtotal - System (sum lines 1-3)			(100,374,591)	(95,101,529)	(101,882,499)	(98,628,929)	(101,922,247)	(98,197,538)	(101,175,941)	(101,318,207)	(98,199,127)	(101,205,083)	(97,723,676)	(100,828,892)	(1,196,558,259)
5	**Subtotal - VA Jurisdictional Amount (line 4 * 85.2872% - DOMLSE Demand Allocator)**	85.2872%	Sched. 8, p.2	**(85,606,678)**	**(81,109,431)**	**(86,892,731)**	**(84,117,852)**	**(86,926,631)**	**(83,749,931)**	**(86,290,127)**	**(86,411,462)**	**(83,751,286)**	**(86,314,982)**	**(83,345,787)**	**(85,994,139)**	**(1,020,511,036)**
6	Underground Transmission Service (Docket EL10-49)		PJM Inv	(817,637)	(763,965)	(816,906)	(790,774)	(817,131)	(790,056)	(814,890)	(814,943)	(788,243)	(813,006)	(785,758)	(814,087)	(9,627,396)
7	**VA Jurisdictional Amount (line 6 * 88.6382% - DOMLSE Demand Allocator-Modified NC)**	88.6382%	Sched. 8, p.2	**(724,739)**	**(677,165)**	**(724,091)**	**(700,928)**	**(724,290)**	**(700,291)**	**(722,304)**	**(722,351)**	**(698,684)**	**(720,634)**	**(696,482)**	**(721,592)**	**(8,533,551)**
8	**Total NITS VA Jurisdictional Amount (line 5 + line 7)**			**(86,331,417)**	**(81,786,596)**	**(87,616,821)**	**(84,818,780)**	**(87,650,921)**	**(84,450,222)**	**(87,012,431)**	**(87,133,813)**	**(84,449,970)**	**(87,035,615)**	**(84,042,269)**	**(86,715,731)**	**(1,029,044,586)**
	Transmission Enhancement															
9	Transmission Enhancement Charges		PJM Inv	(21,184,975)	(21,341,153)	(21,345,716)	(21,351,365)	(21,351,312)	(21,220,173)	(21,182,681)	(21,183,731)	(21,173,245)	(21,135,905)	(21,109,820)	(21,162,605)	(254,742,681)
10	Transmission Enhancement Credits		PJM Inv	26,485,572	26,745,522	26,751,252	26,758,333	26,758,265	26,735,206	26,688,290	26,689,816	26,676,605	26,629,559	26,596,694	26,663,199	320,178,313
11	Dominion Energy Virginia Settlement - EL05-121-009 (east/west)		PJM Inv	(860,256)	(860,909)	(861,092)	(861,320)	(861,317)	(860,576)	(859,002)	(859,012)	(858,587)	(857,073)	(856,015)	(858,156)	(10,313,315)
12	Generation Deactivation Charges		PJM Inv	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Generation Deactivation Credits		PJM Inv	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total Transmission Enhancement (sum lines 9-13)			4,440,341	4,543,460	4,544,444	4,545,647	4,545,636	4,654,457	4,646,607	4,647,073	4,644,773	4,636,581	4,630,859	4,642,438	55,122,316
15	**VA Jurisdictional Amount (line 14 * 85.2872% - DOMLSE Demand Allocator)**	85.2872%	Sched. 8, p.2	**3,787,043**	**3,874,990**	**3,875,829**	**3,876,855**	**3,876,845**	**3,969,656**	**3,962,961**	**3,963,358**	**3,961,397**	**3,954,410**	**3,949,530**	**3,959,405**	**47,012,280**
	PJM Administrative Charges															
16	9-1 Control Area		PJM Inv	(1,963,657)	(1,901,609)	(2,412,097)	(2,126,442)	(2,355,154)	(1,881,128)	(2,052,663)	(1,936,900)	(1,963,269)	(2,147,715)	(2,098,094)	(2,278,773)	(25,117,501)
17	9-2 Financial Transmission Rights		PJM Inv	(13,550)	(12,720)	(16,264)	(14,127)	(15,132)	(17,117)	(17,044)	(16,436)	(16,085)	(16,490)	(16,079)	(16,498)	(187,542)
18	9-2 Financial Transmission Rights - FTR Bid Options x 5		PJM Inv	-	-	-	-	-	-	-	-	-	-	-	-	-
19	9-2 Financial Transmission Rights - FTR Bid Obligations		PJM Inv	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Total PJM Administrative Charges (sum lines 16-19)			(1,977,207)	(1,914,329)	(2,428,361)	(2,140,569)	(2,370,286)	(1,898,245)	(2,069,707)	(1,953,336)	(1,979,354)	(2,164,205)	(2,114,173)	(2,295,271)	(25,305,043)
21	**VA Jurisdictional Amount (line 20 * 82.3977% - DOMLSE Energy Allocator)**	82.3977%	Sched. 8, p.1	**(1,629,173)**	**(1,577,363)**	**(2,000,914)**	**(1,763,780)**	**(1,953,061)**	**(1,564,110)**	**(1,705,391)**	**(1,609,504)**	**(1,630,942)**	**(1,783,255)**	**(1,742,030)**	**(1,891,251)**	**(20,850,773)**
22	**Economic and Emergency Load Response Programs (Energy Only)**		PJM Inv	(271,990)	(14,373)	(18,526)	(4,262)	(41,369)	(102,966)	(79,748)	(119,944)	(220,433)	(89,589)	(228,511)	(87,435)	(1,279,146)
23	**VA Jurisdictional Amount (line 22 * 82.3977% - DOMLSE Energy Allocator)**	82.3977%	Sched. 8, p.1	**(224,114)**	**(11,843)**	**(15,265)**	**(3,512)**	**(34,087)**	**(84,842)**	**(65,710)**	**(98,831)**	**(181,632)**	**(73,819)**	**(188,288)**	**(72,044)**	**(1,053,987)**
24	**Subtotal Costs Subject to Deferral (lines 8 + 15 + 21 + 23)**			**(84,397,661)**	**(79,500,812)**	**(85,757,171)**	**(82,709,216)**	**(85,761,224)**	**(82,129,518)**	**(84,820,571)**	**(84,878,789)**	**(82,301,147)**	**(84,938,280)**	**(82,023,057)**	**(84,719,620)**	**(1,003,937,067)**
25	**Amortization of Actual Under/Over Recovered Costs**		(A)	**(7,788,009)**	**(7,285,557)**	**(7,788,009)**	**(7,536,783)**	**(7,788,009)**	**(7,536,783)**	**(7,788,009)**	**(7,788,009)**	**(18,154,082)**	**(18,759,218)**	**(18,154,082)**	**(18,759,218)**	**(135,125,767)**
26	**Subsection A 4 Costs Monthly Update Amount (from prior year filing)**		(B)	**8,059,189**	**9,957,845**	**8,059,189**	**7,799,215**	**8,059,189**	**7,799,215**	**8,059,189**	**8,059,189**	**-**	**-**	**-**	**-**	**65,852,217**
27	**TOTAL COSTS SUBJECT TO DEFERRAL (lines 24 + 25 + 26)**			**(84,126,481)**	**(76,828,524)**	**(85,485,991)**	**(82,446,784)**	**(85,490,044)**	**(81,867,086)**	**(84,549,391)**	**(84,607,609)**	**(100,455,230)**	**(103,697,498)**	**(100,177,139)**	**(103,478,839)**	**(1,073,210,616)**
28	**Subsection A 4 REVENUES** **Subsection A 4 Retail Revenues - VA Jurisdictional**		(C)	**79,669,081**	**71,429,961**	**65,289,594**	**60,342,324**	**61,985,940**	**81,838,726**	**84,230,491**	**81,835,925**	**77,965,256**	**85,916,735**	**81,273,747**	**103,593,112**	**935,370,890**
29	**Monthly (Under)/Over Recovery (lines 27 + 28)**			**(4,457,400)**	**(5,398,563)**	**(20,196,398)**	**(22,104,460)**	**(23,504,104)**	**(28,360)**	**(318,901)**	**(2,771,685)**	**(22,489,974)**	**(17,780,763)**	**(18,903,392)**	**114,273**	**(137,839,726)**

Notes:
(A) Per financial records at beginning of rate year, provided by Dominion Energy Virginia Corporate Accounting group.
(B) Subsection A 4 Cost of Service Compliance Filing, PUR-2024-00071, Formula Schedule 10.
(C) Revenue provided by Dominion Energy Virginia Corporate Accounting group. Actual monthly recoveries.

Virginia Electric and Power Company
Subsection A 4 Costs
Subsection A 4 Costs Update Calculation
For the Period January 1 through August 31, 2025

Col. No.	1		2	3	4	5	6	7	8	9	10	11	12
Line No.	Description	Source	Annual Amount	Daily Amount	January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	Total
	Subsection A 4 Costs Per Filing PUR-2024-00071												
1	**Network Integration Transmission Service (NITS)**	A	**$1,036,696,848**	$ 2,832,505	$ 87,807,657	$ 82,142,646	$ 87,807,657	$ 84,975,151	$ 87,807,657	$ 84,975,151	$ 87,807,657	$ 87,807,657	$ 691,131,232
	Transmission Enhancement												
2	Charges	A	**$ 222,447,762**	$ 607,781	$ 18,841,204	$ 17,625,642	$ 18,841,204	$ 18,233,423	$ 18,841,204	$ 18,233,423	$ 18,841,204	$ 18,841,204	$ 148,298,508
3	Credits	A	**(278,785,252)**	(761,708)	(23,612,959)	(22,089,542)	(23,612,959)	(22,851,250)	(23,612,959)	(22,851,250)	(23,612,959)	(23,612,959)	(185,856,835)
4	Total Transmission Enhancement (lines 2 + 3)				$ (4,771,755)	$ (4,463,899)	$ (4,771,755)	$ (4,617,827)	$ (4,771,755)	$ (4,617,827)	$ (4,771,755)	$ (4,771,755)	$ (37,558,327)
5	**Total Transmission Costs Per Compliance Filing (lines 1 + 4)**				$ 83,035,902	$ 77,678,747	$ 83,035,902	$ 80,357,324	$ 83,035,902	$ 80,357,324	$ 83,035,902	$ 83,035,902	$ 653,572,905
	Subsection A 4 Costs Per Current Filing												
6	**Network Integration Transmission Service (NITS)**	B	**$1,181,835,731**	$ 3,237,906	$ 100,375,089	$ 90,661,371	$ 100,375,089	$ 97,137,183	$ 100,375,089	$ 97,137,183	$ 100,375,089	$ 100,375,089	$ 786,811,185
	Transmission Enhancement												
7	Charges	B	**$ 245,831,441**	$ 673,511	$ 20,878,835	$ 18,858,302	$ 20,878,835	$ 20,205,324	$ 20,878,835	$ 20,205,324	$ 20,878,835	$ 20,878,835	$ 163,663,124
8	Credits	B	**(321,919,961)**	(881,972)	(27,341,147)	(24,695,230)	(27,341,147)	(26,459,175)	(27,341,147)	(26,459,175)	(27,341,147)	(27,341,147)	(214,319,316)
9	Total Transmission Enhancement (lines 7 + 8)				$ (6,462,313)	$ (5,836,928)	$ (6,462,313)	$ (6,253,851)	$ (6,462,313)	$ (6,253,851)	$ (6,462,313)	$ (6,462,313)	$ (50,656,193)
10	**Total Transmission Costs Per Current Filing (lines 6 + 9)**				$ 93,912,777	$ 84,824,444	$ 93,912,777	$ 90,883,332	$ 93,912,777	$ 90,883,332	$ 93,912,777	$ 93,912,777	$ 736,154,992
	Subsection A 4 Costs - Monthly Update Amount												
11	**Network Integration Transmission Service (NITS) (line 6 - line 1)**				$ 12,567,433	$ 8,518,725	$ 12,567,433	$ 12,162,032	$ 12,567,433	$ 12,162,032	$ 12,567,433	$ 12,567,433	$ 95,679,953
	Transmission Enhancement												
12	Charges (line 7 - line 2)				$ 2,037,631	$ 1,232,660	$ 2,037,631	$ 1,971,901	$ 2,037,631	$ 1,971,901	$ 2,037,631	$ 2,037,631	$ 15,364,616
13	Credits (line 8 - line 3)				(3,728,189)	(2,605,688)	(3,728,189)	(3,607,925)	(3,728,189)	(3,607,925)	(3,728,189)	(3,728,189)	(28,462,482)
14	Total Transmission Enhancement (lines 12 + 13)				$ (1,690,558)	$ (1,373,028)	$ (1,690,558)	$ (1,636,024)	$ (1,690,558)	$ (1,636,024)	$ (1,690,558)	$ (1,690,558)	$ (13,097,866)
15	**Total Subsection A 4 Costs - Monthly Update Amount (lines 11 + 14)**				$ 10,876,875	$ 7,145,697	$ 10,876,875	$ 10,526,008	$ 10,876,875	$ 10,526,008	$ 10,876,875	$ 10,876,875	$ 82,582,087

Note A: Subsection A 4 Cost of Service Compliance Filing, PUR-2024-00071, Formula Schedule 2.
Note B: Formula Schedule 2 - Current Filing.

Virginia Electric and Power Company
Rider T1 Rate Adjustment Clause
Comparison of Current Rider T Rates in Effect Projected Over 2025-2026 Rate Year with Subsection A 4 Costs
Virginia Jurisdiction

Component	Current Subsection A 4 Rates Included In Base rates In Effect Projected Over 2025/2026 Rate Year	Subsection A 4 Costs	Rider T1 Increment/(Decrement) RAC
Subsection A 4 Revenue Requiremen	$ 560,916,458 [1]	$ 1,343,335,735	$ 782,419,277

1 Per Company Witness Givens's Testimony - Transmission Revenues projected over Rate Year ended August 31, 2026, based on rates currently in effect as approved in Case No. PUR-2024-00071.

<u>WITNESS DIRECT TESTIMONY SUMMARY</u>

<u>Witness</u>: Michael J. Batta
<u>Title</u>: Senior Strategic Advisor in the FERC Policy Group
<u>Summary</u>:

Company Witness Michael J. Batta provides detailed information supporting the rate year revenue requirement that the Company is seeking to recover in this proceeding through a combination of the Subsection A 4 component of base rates (the Company's former Rider T) and a Subsection A 4 RAC, designated Rider T1, from Virginia jurisdictional retail customers for the twelve-month rate year beginning September 1, 2025.

Mr. Batta (1) gives an overview of PJM, the regional transmission entity of which the Company is a member; (2) describes the Subsection A 4 services and programs provided and administered by PJM; and (3) discusses for purposes of the statute and cost recovery how these Subsection A 4 services and programs are charged to the Company by PJM under rates, terms, and conditions approved by the FERC for the purpose of serving Virginia jurisdictional retail customers.

Additionally, Mr. Batta sponsors Filing Schedule 46B, which contains the relevant FERC orders that were issued since last year's Rider T1 proceeding, Case No. PUR-2024-00071 (the "2024 Rider T1 Case").

DIRECT TESTIMONY
OF
MICHAEL J. BATTA
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2025-00076

Q. Please state your name, position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), and business address.

A. My name is Michael J. Batta, and I am a Senior Strategic Advisor in the FERC Policy Group for the Company. My business address is 120 Tredegar Street, RS-4, Richmond, Virginia 23219. A statement of my background and qualifications is attached as Appendix A.

Q. Please describe your areas of responsibility with the Company.

A. I have been actively involved in managing the regulatory policy issues related to electric transmission on behalf of the Company since last year's Rider T1 proceeding, Case No. PUR-2024-00071 (the "2024 Rider T1 Case"), including: (1) updating the Company's Federal Energy Regulatory Commission ("FERC") formula rate; (2) advising on customer information requests; (3) advising on transmission rate and cost allocation proposals, as well as other FERC matters that could affect the Company's transmission costs; (4) representing the Company on Regional Transmission Organization ("RTO") issues before PJM Interconnection, L.L.C. ("PJM") and the associated stakeholder bodies; and (5) providing regulatory support in the Company's rate adjustment clause ("RAC") filings for cost recovery under § 56-585.1 A 4 ("Subsection A 4") of the Code of Virginia before the State Corporation Commission of Virginia (the "Commission").

Q. Will you be introducing any exhibits with your testimony?

A. Yes, Company Exhibit No. __, MJB, consisting of Schedules 1-3, was prepared by me, and/or under my supervision, and is accurate and complete to the best of my knowledge and belief. References to bank account information for PJM in Schedules 1(a) and 1(b) have been redacted consistent with such treatment in the 2024 Rider T1 Case, and PJM's redaction requirement on the cover page of each PJM monthly invoice. I am also sponsoring Filing Schedule 46B, which is included in the Company's Application pursuant to the Commission's Rules Governing Utility Rate Applications and Annual Informational Filings of Investor-Owned Electric Utilities, 20 VAC 5-204-5, *et seq.* ("Rate Case Rules").

Q. Is Filing Schedule 46B organized in the same manner as it was in the Company's previous Subsection A 4 RAC proceedings?

A. Yes, it is. Consistent with the Commission's grant of an ongoing limited waiver in Case No. PUE-2012-00052, Filing Schedule 46B contains only those relevant FERC orders that were issued since the 2024 Rider T1 Case. In other words, the Filing Schedule 46B that I am sponsoring in this proceeding contains only the applicable interim FERC orders that were not previously included in Filing Schedule 46B in earlier Rider T and T1 cases.

To ensure that the Commission continues to receive complete information about older FERC dockets that are applicable to Subsection A 4 cost recovery, but not included in Filing Schedule 46B because no new applicable orders affecting Subsection A 4 cost recovery were issued therein, I am continuing to list all of the dockets pertaining to the FERC-approved tariffs forming the basis for cost recovery under Subsection A 4. This is the same approach used in the 2012 through 2024 Rider T1 Cases.

In addition, consistent with the requirements set forth in Rule 90 of the Rate Case Rules, 20 VAC 5-204-90, Filing Schedule 46B complies with the updated instructions for schedules and exhibits effective as of January 1, 2021.

Q. Please describe the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to provide detailed information supporting the rate year revenue requirement that the Company is seeking to recover in this proceeding through a combination of the Subsection A 4 component of base rates (the Company's former Rider T) and a Subsection A 4 RAC, designated Rider T1, from Virginia jurisdictional retail customers for the twelve-month rate year beginning September 1, 2025, and ending August 31, 2026 (the "Rate Year"). More specifically, as in previous Rider T and Rider T1 cases, I will: (1) provide an overview of PJM, the regional transmission entity (or RTO) of which the Company is a member; (2) describe the Subsection A 4 services and programs provided and administered by PJM; and (3) discuss for purposes of the statute and cost recovery how these Subsection A 4 services and programs are charged to the Company by PJM under rates, terms, and conditions approved by the FERC for the purpose of serving Virginia jurisdictional retail customers.

Subsection A 4 states in relevant part that the following costs "shall be deemed reasonable and prudent" and recovered "on a timely and current basis" from customers:

> (i) costs for transmission services provided to the utility by the regional transmission entity of which the utility is a member, as determined under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission; [and] (ii) costs charged to the utility that are associated with demand response programs approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member;….

Consistent with the Commission's Final Order dated June 29, 2009, in Case No. PUE-2009-00018 (the "2009 Rider T Case"), as explained herein, the Company is again not seeking recovery of certain PJM-related administrative charges in this case.

Q. Please describe the function of PJM and the general nature of the services that it provides.

A. PJM is a FERC-approved regional transmission entity (as defined by Subsection A 4) or RTO that coordinates the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia. It acts independently in managing the regional transmission system and wholesale electricity market. Accordingly, PJM ensures the reliability of one of the largest centrally dispatched electrical grids in North America. It has about 1,100 members – including power generators, transmission owners, electric distributors, power marketers, and large consumers. PJM's operations include balancing electricity supply and demand, conducting dispatch operations, and monitoring the status of a grid comprised of over 88,000 miles of transmission lines. Thus, PJM has a broad view of regional conditions and reliability issues, including those in neighboring systems. PJM's organized electricity market coordinates the continuous buying, selling, and delivery of wholesale electricity through competitive spot markets, and PJM's markets are monitored by an independent market monitor. It also provides online tools that enable members/customers to submit bids and offers that facilitate energy trading, and supplies continuous real-time data to such entities.

Additionally, PJM manages a comprehensive regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system. It is responsible for managing changes to the grid to accommodate new generating plants, substations, and transmission lines. PJM analyzes and forecasts the future electricity needs of the region, and its planning process ensures that reliability is maintained.

Finally, PJM has developed both emergency and economic load response programs. As a way to provide compensation for the system benefits such programs can provide, the PJM Emergency and Pre-Emergency Load Response Program enables load management resources (*i.e.*, resources with demonstrated capabilities to provide reductions in demands or to otherwise control loads) to receive payments for reducing load during emergency conditions or pre-emergency conditions. The PJM Economic Load Response Program, in turn, enables load management resources to receive payments for reducing consumption in response to PJM market prices for electricity.

Q. Please describe how the Company interfaces with PJM.

A. Like several other load serving entities in PJM, the Company provides its retail customers with generation and distribution services and fulfills many of its retail customer obligations – including the provision of transmission and ancillary services – through its participation in the RTO. Upon its May 2005 integration into PJM, the Company ceased to be a control area operator and transferred its control area and balancing authority obligations to PJM, which is now responsible for those obligations. Thus, the Company's former control area became what is now known as the Dominion Energy Virginia zone (the "Dominion Zone" or "Dom Zone").

Once the Company joined the RTO, PJM started providing services to the Company under the PJM Open Access Transmission Tariff ("PJM OATT"), thereby eliminating services that the Company had previously provided for itself pursuant to its own Open

Access Transmission Tariff in effect before integration. The PJM OATT is a FERC-approved transmission tariff that governs the rates, terms, and conditions of the markets and services administered and provided by PJM.[1]

As a member of PJM, the Company is viewed as having four different primary accounts: Load Serving Entity ("DOMLSE"), Generation Owner ("DOMGEN"), Electric Distribution Company ("DOMEDC"), and Curtailment Service Provider ("DOMCSP"). Additionally, the "PEPDVP" account has been established to settle the delivery of energy pursuant to an interconnection agreement arrangement between the Company and Potomac Electric Power Company ("PEPCO"). Finally, Dominion Energy Virginia has several other PJM accounts (*e.g.*, for ring-fenced solar projects, etc.) that are not relevant to Rider T1.

Relevant to Rider T1, each of these accounts is billed charges by (or receives credits from) PJM for services and programs as described below. The Company is an electric distribution company ("EDC") within the Dom Zone, and one of approximately a dozen load serving entities ("LSEs") currently providing electric service to retail customers within the Dom Zone. The Company's LSE function, DOMLSE, obtains transmission, capacity, energy, and ancillary services from PJM and the markets that PJM administers, and the DOMLSE account is charged by PJM for these services.

As a Generation Owner, the Company provides electric generation, capacity, and energy, as well as generation-related ancillary services to the markets administered by PJM, and

[1] *See* https://www.pjm.com/directory/merged-tariffs/oatt.pdf.

the DOMGEN account receives credits from PJM for these services.

As a Transmission Owner, the Company has turned over operational control of its transmission system to PJM, and the DOMEDC account receives credits from PJM for use of the Company's transmission facilities. Both PJM as a Transmission Provider, and the Company as a Transmission Owner, are subject to the FERC-approved mandatory reliability standards established and enforced by the North American Electric Reliability Corporation ("NERC").

Finally, the Company established the DOMCSP account so that it could enter demand-side resources, a term used here interchangeably with load management resources, into PJM's capacity markets.

Q. Please generally describe how PJM assesses charges and credits to the Company.

A. The costs of providing services to PJM market participants are charged according to the FERC-approved PJM OATT.[2] PJM applies these tariff rates to the various generation and load billing determinants as specified in the PJM OATT. As part of the PJM settlement process, PJM charges and credits DOMLSE, DOMGEN, and DOMCSP for services provided to and by the Company on behalf of its wholesale and retail customers within the Dom Zone. The monthly charges incurred by the Company include all applicable tariff rates under the PJM OATT, applied to the various billing determinants

[2] In *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008), the FERC adopted regulations requiring that tariffs and tariff-related filings be made electronically. As part of its transition to electronic tariff filings, the FERC required that regulated entities make "baseline" tariff filings, which were to reflect existing accepted tariffs with no proposed substantive changes or revisions. In compliance with this directive, PJM submitted its baseline filing on September 17, 2010, and has since amended it on several occasions. This baseline filing contained every sheet in the PJM OATT that had been accepted up to that date, and provided a starting point for electronic maintenance of the PJM OATT in FERC's eTariff database. The FERC accepted PJM's baseline filing by order issued December 20, 2010, in Docket No. ER10-2710.

for the DOMLSE, DOMGEN, and DOMCSP functions. Portions of these billing determinants are directly related to the load requirements of the Virginia jurisdictional retail customers served by the Company. Likewise, the Company receives monthly credits for services that the Company provides in return under the PJM OATT and the PJM Operating Agreement (the provisions of Schedule 1 of this agreement are included in Attachment K of the PJM OATT) through the DOMLSE, DOMGEN, DOMEDC, and DOMCSP accounts.

For reference, a copy of PJM's monthly billing statement to the Company for February 2025 is attached as my Schedule 1. This billing statement shows the various PJM charges and credits broken out by each of the Company's functions and accounts. Using my Schedule 1, I will discuss later in more detail the particular charges and credits billed by PJM that are appropriate for recovery through Subsection A 4.

As explained by Company Witness David M. Wilkinson, the costs that the Company is seeking to recover in this proceeding, which are described in Subsection A 4, are derived from the FERC-approved tariff rates contained in the PJM OATT. These Subsection A 4 costs are identified from PJM's monthly billing statements (included in Filing Schedule 46A, which Mr. Wilkinson sponsors). Mr. Wilkinson further explains how these costs are allocated or assigned to Virginia jurisdictional customers.

I will now discuss these PJM charges and credits below on a functional basis (*i.e.*, on the basis of DOMLSE and DOMGEN), and not according to those portions that are allocated or assigned to the Virginia retail jurisdiction.

Q. As a preliminary matter, does Subsection A 4 specify the FERC-approved, RTO-related costs subject to recovery through a Subsection A 4 RAC?

A. Yes. The FERC-approved, RTO-administered costs identified for recovery under Subsection A 4 include "without limitation, costs for transmission service; charges for new and existing transmission facilities, …; administrative charges; and ancillary service charges designed to recover transmission costs;" as well as "costs charged to the utility that are associated with demand response programs . . . ."

Q. Please provide a detailed definition of, and PJM OATT reference for, each of these Subsection A 4 categories of costs.

A. The following definitions and references apply to the Subsection A 4 categories of costs expressly identified in the statute:

1. **"costs for transmission service"** – These costs comprise the FERC-approved Annual Transmission Revenue Requirement ("ATRR") associated with the transmission facilities in a specific PJM zone. For the Dom Zone, the ATRR includes costs for the existing transmission system and costs for new transmission facilities that are projected to be placed into service during the same calendar year for which the ATRR is being determined. These costs are currently recovered from customers pursuant to Section 34, "Rates and Charges," of the PJM OATT using the Network Integration Transmission Service ("NITS") rate for the Company. The Company's NITS rate is determined in accordance with Attachment H-16A of the PJM OATT and, as included as Schedule 3 of my testimony, the applicable formula rate implementation protocols in Attachment H-16B of the PJM OATT.

   In FERC Docket No. EL10-49, the inclusion of costs for certain transmission facilities in the calculation of the Company's NITS rate were challenged on the basis that these facilities do not benefit certain network customers in the Dom Zone. On May 18, 2012, the FERC approved an uncontested settlement in Docket No. EL10-49, resolving the cost allocation of all of the transmission facilities set for hearing in that case except for the incremental costs of undergrounding the Garrisonville, Pleasant View-Hamilton, and Beaumeade-NIVO (also referred to as DuPont Fabros) projects (the "Projects"). As part of this settlement, the Company incurred an additional charge for transmission service, included in Attachment H-16AA of the PJM OATT which expired on June 30, 2022 as I discuss later in my testimony, referred to by Company Witness Wilkinson in his pre-filed direct testimony as the Dominion Energy Virginia Settlement Charge. Also discussed later in this testimony, are the incremental costs of undergrounding the Projects that are being recovered by a UG Transmission Charge.

2. **"charges for new and existing transmission facilities"** – These costs are associated with the FERC-approved annual revenue requirements of required transmission enhancements (or baseline transmission projects) developed in accordance with PJM's Regional Transmission Expansion Plan ("RTEP"). The RTEP is developed annually pursuant to Schedule 6 of the PJM Operating Agreement and shall include, *inter alia,* the individual transmission owner FERC filed planning criteria as filed in FERC Form No. 715. The Company submits as part of its FERC Form No. 715 individual transmission owner planning criteria regional end-of-life electric transmission lines operated at 500 kV and above; therefore, such FERC Form No. 715 projects are included in PJM's RTEP as baseline transmission projects. The

subject transmission project costs are allocated by PJM to the various transmission zones within PJM in accordance with allocation methods approved by the FERC. The allocation factors used are set forth in Schedule 12 – Appendix and Schedule 12 – Appendix A of the PJM OATT. The annual revenue requirement for any transmission project to be charged in accordance with Schedule 12 (with crediting to assure no duplication of costs recovered in the NITS rate) is included in either a formula rate annual update or a separate rate filing approved by the FERC, as described in detail below. Also, there are RTEP costs associated with the settlement in Docket No. EL05-121-009 (the "East/West Settlement") that are discussed later in this testimony. Additionally, these costs could include an allocation of the costs of certain interregional transmission projects located in the PJM region and other regions pursuant to the agreements listed in Schedule 12 – Appendix B of the PJM OATT. In the case of a transmission enhancement needed to alleviate the reliability impact of a deactivating generating unit, NITS customers that are allocated a share of the costs of such a reliability upgrade are, in accordance with Part V of the PJM OATT, allocated a share of any additional transmission charge to compensate such a deactivating generator owner for its costs incurred while delaying deactivation beyond its desired deactivation date.

3. **"administrative charges"** – These charges are intended to recover the costs associated with operating PJM, and for funding various organizations through schedules included in the PJM OATT. These charges are included in Schedule 9 of the PJM OATT and its subsidiary schedules. A more detailed description of administrative charges for which the Company is seeking recovery through

Subsection A 4 is provided later in my testimony.

4. **"ancillary service charges designed to recover transmission costs"** – PJM charges these costs for the Transmission Owner Scheduling, System Control, and Dispatch Service ancillary services provided in accordance with Schedule 1A of the PJM OATT. The Company currently recovers these costs through its NITS rate, which is discussed above, and therefore does not have a separate rate included in this Schedule 1A.

5. **"costs charged to the utility that are associated with demand response programs approved by the [FERC]"** – These are the costs related to PJM's demand response programs. Currently, PJM administers two such programs – the Economic Load Response Program and the Emergency and Pre-Emergency Load Response Program. The costs associated with these demand response programs are determined in accordance with Section 3.3A Economic Load Response Participants of Attachment K-Appendix of the PJM OATT, and Appendix Section 8 of that same attachment (labeled "Emergency and Pre-Emergency Load Response Program"). I will provide a more detailed description of these programs later in my testimony.

Q. Please describe the PJM billing process for transmission service costs.

A. DOMLSE purchases transmission service for customers served by the Company based upon their contribution to the metered demand coincident with each of the Dominion Zone's twelve monthly transmission peaks during the twelve-month period ending September 30. This is shown as NITS charges on the PJM monthly billing statements to the Company, which PJM bills in accordance with Section 34 of the PJM OATT. Section

34, approved in FERC Docket Nos. EL02-121, *et al.*; EL05-127, *et al.*; EL06-55, *et al.*; ER10-2710; ER11-2527; and ER20-646 describes the "Rates and Charges" pertaining to NITS provided pursuant to the PJM OATT. The Company's NITS rate, approved by the FERC in Docket No. ER08-92, as revised in Docket Nos. ER10-557, ER10-2710, ER11-2801, ER14-1549, ER14-1831, ER15-856-000, ER15-1487-000, ER15-1504-000, ER14-1831-001, ER16-2116-000, ER17-479-000, ER17-714-000, ER17-714-001, ER18-318-000, ER18-318-001, ER18-1351-000, EL18-167, ER19-839-000, ER19-839-001, ER19-1569-000, ER19-2714-000, ER20-1085-000 et al., ER21-1680-000, ER21-2518-000, ER22-2443-001, and ER23-1646-000 includes the formula in Attachment H-16A of the PJM OATT for determining the cost of service, or ATRR, associated with the existing transmission system and with new transmission projects being constructed by the Company that are planned to be in service during the calendar year that the rate is charged.

For example, during the 2025 calendar year, the ATRR would include new transmission facilities that are planned to be placed in service during 2025. As approved by the FERC in Docket Nos. ER08-1207 and ER08-1207-002, some transmission projects include "Incentive Return on Equity ("ROE") Adders" in accordance with FERC guidelines as defined in Section 219 of the Federal Power Act[3] and FERC Order Nos. 679, *et al.*[4] The costs of the Incentive ROE Adders for PJM non-RTEP baseline projects are recovered from customers through the Company's NITS rate.

[3] 16 U.S.C. § 825s.
[4] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

As I previously noted, the Company's NITS rate is determined in accordance with Attachment H-16A of the PJM OATT and applicable formula rate implementation protocols in Attachment H-16B. The specific NITS rate and ATRR are updated each year and posted publicly on PJM's website.[5] All LSEs in the Dom Zone, including DOMLSE, receive a share of the revenues that PJM receives for providing both firm and non-firm point-to-point transmission services. These revenues are included as credits on the monthly PJM invoices and have the effect of reducing the cost of such transmission services.

For example, my Schedule 1, Page 2, line 1100 shows that the NITS charge to DOMLSE for the February[6] 2025 billing period was $106,371,492. Comparably, Schedule 1, Page 6, line 2130 shows the February 2025 credit for Firm Point-to-Point Transmission Service of $1,815,251 and, on line 2140, the February 2025 credit for Non-Firm Point-to-Point Transmission Service of $215,333. Further, on line 2140A on Page 7, there is an additional Non-Firm Point-to-Point Transmission Service Credit adjustment of $832. The NITS charges and credits for point-to-point transmission service are netted together to determine the costs recoverable under Subsection A 4. For reference, in Table 1 on Page 1 of Schedule 2, I show how the NITS charge to DOMLSE is calculated for the month of February 2025. Accordingly, the $106,371,492 amount shown on line 4 of this Table 1 is the same amount shown in Schedule 1, Page 2 on line 1100 of the February

[5] *See* https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx.

[6] Note that I used the January billing period for illustrative purposes in previous iterations of my Rider T1 testimony through 2021. However, due to certain one-time adjustments exclusive to the January 2025 billing only, the charges and credits from the January 2025 billing period do not succinctly represent the range of charges and credits that are expected be applied during each month thereafter in 2025; therefore, the February 2025 invoice is being used as an example throughout this testimony, consistent with how my testimony has been presented since the 2022 Rider T1 Case.

2025 bill to the DOMLSE account.

Q. Do the Attachment H-16B Formula Rate Implementation Protocols allow parties to review and challenge the inputs to the NITS rate?

A. Yes. In paragraph 48 of the Order on Formula Rate Proposal (Docket Nos. ER08-92-000, *et al.*), the FERC acknowledged that "VEPCO [*i.e.*, the Company] has committed, in its protocols, to provide information to its customers and to respond to information requests by such customers." Additionally, in the same paragraph, the FERC stated: "We expect VEPCO to provide data to its customers relating to both the Annual Update and True-up Adjustment in a timely manner, hold a customer meeting to explain the data, and respond to requests for further information." As FERC clearly expects, the Company follows the procedures in its formula rate implementation protocols, which are included as Schedule 3, to allow parties the opportunity to review the data that goes into updating the NITS rate each year. The Annual Update and True-up Adjustment used to update the NITS rate each year is reviewed during the year before the updated rate is charged by PJM. For example, the review of the 2025 projected inputs and 2023 actual inputs (associated with the true-up component) to the 2025 NITS rate took place in 2024. As part of this review, the Company provided data and responses to numerous information requests in accordance with the annual review procedures of Section 2 of the protocols.

The Company works closely with interested parties during each Annual Update and True-Up Adjustment to address any issues and/or concerns that may arise from a preliminary challenge in accordance with Section 3a of the protocols. The Company may, and has done so in the past, agreed to make input changes resulting from a preliminary challenge. While the Company seeks to satisfactorily resolve all preliminary challenges, sometimes it is unable to come to agreement with the parties raising them. If satisfactory resolution of a preliminary challenge is not reached, the unresolved issue(s) can be addressed at FERC through a formal complaint process, as described in Section 3b of the protocols. For example, the discussion of FERC Docket No. EL10-49 throughout my testimony shows this formal complaint process in action.

Q. Please describe the FERC order (ER19-1661-000) approving the change from a one coincident peak to an average 12 coincident peak allocation factor for NITS customers in the Dominion Zone.

A. On April 24, 2019, the Company submitted proposed tariff revisions to the PJM OATT to incorporate a new Attachment M-2. The proposed Attachment M-2 changed the calculation of Network Service Peak Load ("NSPL") for transmission customers within the Dominion Zone to a new twelve-month coincident peak ("12-CP") allocation method. On October 17, 2019, FERC accepted the Company's proposed tariff revisions, effective January 1, 2020, as requested.

Q. Please describe the Company's incorporation of the Attachment M-2 into the PJM OATT.

A. As explained further below, the Company's proposal to change the methodology from a 1-CP to a 12-CP was in order to reduce yearly volatility in transmission charges due to seasonal peak changes experienced in the Dominion Zone and to discourage cost-shifting among Network Customers within the Dominion Zone. Prior to the implementation of Attachment M-2, billing was calculated using a single-hour snapshot of customer demand. As a result and as explained in the Company's proceeding in ER19-1661, this single-hour snapshot (1-CP) could result in large changes in cost responsibility from year to year depending on when the annual system peak occurred (summer or winter), and it incentivized load serving entities to forecast the annual peak and intentionally reduce their load in that specific hour to avoid charges for transmission service. The Company argued that reducing load in this manner could significantly reduce or even eliminate a customer's responsibility for transmission service charges for an entire year. Furthermore, the Company demonstrated that Network Customers that are able to curtail their load during the 1-CP have reduced their allocated NITS costs and shifted these costs to other customers. By implementing a 12-CP allocation feature through the Attachment M-2, this results in a more stable cost allocation by dampening cost shifts due to changes in the annual system peak. Using a 12-CP methodology evens out this allocation by using loads during each monthly peak, thereby allowing the NITS costs to be allocated based on a much broader range of system usage conditions throughout the year instead of using only the 1-CP that is based on 1 hour of 8,760 hours in a year.

Q. Did the Company propose a change to its NITS rate as a result of Attachment M-2?

A. No, the Company's NITS rate was not altered as a result of Attachment M-2. Instead, the Company sought in its filing in ER19-1661 to change the method by which the costs are allocated between Network Customers/LSEs. Furthermore, the Company did not propose any changes to its transmission service formula rate (Attachment H-16A); therefore, the 1-CP demand remains the divisor for NITS charges in the formula rate, and the NITS rate did not change as a result of the transition from 1-CP to 12-CP.

Q. Please describe how the 12-CP methodology is used and how it relates to the NITS rate.

A. With the 12-CP methodology, the Company collects hourly load data for all Network

Customers (*i.e.*, a customer taking NITS) in the Dominion Zone (including applicable losses) coincident with each of the Dominion Zone's twelve monthly transmission peaks during the twelve-month period ending September 30 of the prior calendar year, and then calculates a Network Customer's average 12-CP value by dividing the sum of the twelve coincident peak load values for that customer by twelve. Each Network Customer's 12-CP allocation factor is then determined by dividing the Network Customer's average 12-CP value by the average 12-CP for the entire Dominion Zone. Then, each Network Customer's NSPL is calculated by multiplying its 12-CP allocation factor by the Dominion Zone's NSPL, or 1-CP. Finally, each Network Customer's calculated NSPL is multiplied by the Company's NITS rate for the applicable month to establish the customer's NITS charges. In other words, the sum of all the NSPL's will equal to the Dominion Zone NSPL, which equals the 1-CP divisor used in the formula rate.

Q. Please describe the PJM billing process for RTEP transmission facilities.

A. The PJM RTEP process is a joint transmission planning process developed to meet the transmission needs in the PJM Region on a reliable, economical, and environmentally acceptable basis. It identifies system upgrades and enhancements required to preserve the reliability of the electrical grid for a region encompassing multiple transmission owner systems. The PJM RTEP process also identifies system upgrades and enhancements through an interregional coordinated system plan with the Midcontinent Independent Transmission System Operator, Inc. ("MISO") by including Targeted Market Efficiency Projects ("TMEP") that address historical market efficiency congestion and demonstrate interregional benefits; thus, transmission costs are distributed amongst both regions based on congestion relief. Transmission projects identified in the

RTEP process can be charged and credited in accordance with Schedule 12 of the PJM OATT, and included on the monthly PJM invoices as Transmission Enhancement Charges (“TEC”) – or they can be charged in transmission rates applicable to the PJM transmission zones where the projects are located.

The TEC consist of two components. The first is a charge that occurs when DOMLSE is billed by PJM for the DOMLSE-allocated portion of the revenue requirements for RTEP projects constructed by all transmission owners in PJM, including the Company’s own projects approved for cost recovery pursuant to Schedule 12 by the FERC, in addition to revenue requirements for TMEPs constructed by transmission owners in MISO and/or PJM which have interregional benefits. The second component is a credit to compensate DOMLSE for its allocated share of the revenues, excluding any Incentive ROE Adders revenues, for RTEP baseline projects constructed by the Company and charged to responsible customers in accordance with Schedule 12, whether such revenues are from the TEC paid by LSEs that serve loads in the Dom Zone or by LSEs that serve loads in other PJM zones. The distribution of these RTEP project charges and credits is described in Schedule 12, including Schedule 12 – Appendix and Schedule 12 – Appendix A, of the PJM OATT. These charges and credits, in turn, were approved by the FERC in the following dockets:

Table 1: FERC Dockets Approving PJM OATT Schedule 12 RTEP Project Charges and Credits

EL02-111	ER10-268	ER12-745	ER15-2562 et al.	ER17-950-000, -001	ER20-1165-000	ER23-1828-000

EL03-212	ER10-2710	ER12-773	ER15-596	ER18-1131-000	ER20-1883-000	ER23-2612-001, -002
EL04-135	ER10-529	ER13-1927	ER15-758-000, -001	ER18-1385-000	ER20-1913-000	ER23-364-000
EL05-121	ER10-549	ER13-198-001 et al.	ER16-1232-000, -001	ER18-1578-000	ER20-262-000	ER23-712-000
EL05-121-006, -008, -009	ER10-893	ER13-198-003 et al.	ER16-1335-002	ER18-1905-000, -001	ER20-2762-000	ER23-779-000
EL07-57	ER10-907	ER13-397-000	ER16-1737-000	ER18-2028-000, -001	ER20-717-000	ER24-1607
EL15-95-003, -004	ER11-2140	ER13-673	ER16-2539-000	ER18-2102-000, -001, -004	ER20-736-000	ER24-1626
EL18-173-000, -001	ER11-2527	ER13-703	ER16-319-000	ER18-2197-000	ER20-776-000	ER24-1942-000, -001
ER04-156	ER11-2578	ER13-90	ER16-676-000	ER18-2350-000	ER21-1364-000	ER24-284-000
ER05-513	ER11-2622	ER14-1485-000, -004	ER16-736-001 et al.	ER18-313-000	ER21-1987-000	ER24-2990
ER05-6	ER11-3106	ER14-2557	ER16-736-003 et al.	ER18-579-000, -001	ER21-2774-000, -001	ER24-319-000
ER06-1271	ER11-4367	ER14-2697	ER17-1016-000, -002	ER18-614-000, -001, -002, -003, -004, -005	ER21-726-000, -001	ER24-321-000
ER06-456	ER12-1130	ER14-274	ER17-1061-001	ER18-680-003	ER21-841-000	ER24-786-000
ER06-456-021 et al.	ER12-1511	ER14-2864-000, -001	ER17-1236-000, -001	ER19-1173-000	ER22-135-000	ER24-843-000
ER06-880	ER12-1661	ER14-2867-001	ER17-1406-000	ER19-1301-000	ER22-1397-000	ER25-775
ER06-954	ER12-1700	ER14-909	ER17-1420-000, -001	ER19-1501-000	ER22-1606-000	
ER07-424	ER12-2288	ER14-972-000	ER17-1679-000	ER19-2708-001	ER22-2653-000	
ER09-204	ER12-2412	ER15-1344-001, -002, -003	ER17-2362-000	ER19-276-000	ER22-702-000	
ER09-484	ER12-2438	ER15-1344-007	ER17-381-000	ER19-521-000	ER22-788-000	

ER09-497	ER12-2440	ER15-1387-000, -001, -002, -003	ER17-725-000	ER19-745-000	ER23-1399-000	
ER09-913	ER12-445	ER15-1387-006	ER17-753-001	ER19-772-000	ER23-1408-000, -001	

The annual revenue requirements that support the TEC to DOMLSE were calculated in accordance with formulas set forth in subparts of Attachment H of the PJM OATT and approved by the FERC. The specific Attachment H subparts of the PJM OATT, the transmission owner companies, and docket numbers of the cases approving the annual revenue requirements used to calculate the TEC to DOMLSE are identified as follows:

Table 2: FERC Dockets Approving Transmission Owner Companies' Annual Revenue Requirements

PJM OATT Attachment	Transmission Owner	Docket No.
Attachment H-1	**Atlantic City Electric Co.**	ER05-515
		ER07-913
		ER08-1423
		ER10-2710
		ER16-456-001, -002
		ER19-18-003, -005
		ER20-1187-000
		ER20-2197-001
		ER20-2197-003
		ER21-201-002, -003
		ER21-201-004
		ER21-2965-000, -001
		ER21-2965-002
		ER22-2200-000, -001
		ER22-2200-002
		ER25-140
Attachment H-2	**Baltimore Gas and Electric Co.**	ER05-515
		ER07-576
		ER10-2710
		ER12-306
		ER15-2253-000
		ER15-2331-000, -001
		ER15-536-000, -002

		ER15-950
		ER16-456-001, -002
		ER17-1016-000, -001, -002
		ER18-404-000
		ER19-14-005
		ER19-500-000
		ER20-1929-000, -001
		ER20-789-000
		ER21-201-004
		ER21-2023-000, -001
		ER21-203-002, -003
		ER21-203-004
		ER21-214-000, -001, -002
		ER21-214-003
		ER21-98-000
		ER24-1313
		ER24-163
		ER24-754-000
		ER25-514
Attachment H-3	**Delmarva Power & Light Co.**	ER05-515
		ER07-914
		ER08-1423
		ER10-2710
		ER13-607-000, -001, -002, -003, et al.
		ER16-456-001, -002
		ER19-6-006
		ER20-1188-000
		ER20-2198-000
		ER20-227-001
		ER21-205-002, -003
		ER21-2965-000, -001
		ER22-2201-000, -001, -002
		ER25-141-000
Attachment H-7	**PECO**	ER17-1510-000
		ER17-1519-000 Errata
		ER17-1519-000, -001, -002
		ER19-124-000
		ER20-1383-001
		ER21-1530
		ER21-209-000, -001, -002, -003
		ER21-2965-000, -001

		ER22-1448-000
		ER23-1514-000
		ER24-1649-000
		ER25-142-000
Attachment H-8	**PPL Utilities**	ER08-1457
		ER10-1209
		ER10-152
		ER10-2710
		ER12-1397
		ER13-1026
		ER13-2410-000
		ER15-1488-000
		ER18-22-001
		ER19-1145-000
		ER19-1145-001
		ER19-2274-000
		ER20-1719-001, -002, -003, -004
		ER20-1739-000, -001
		ER21-2724-000
		ER22-2719-001, -002
		ER23-1629-000
Attachment H-9	**PEPCO**	ER05-515
		ER07-912
		ER08-1423
		ER10-2710
		ER13-607-000, -001, -002, -003, et al.
		ER15-1374-000
		ER16-456-001, -002
		ER19-10-003
		ER19-1145-001
		ER19-1475-002, -004
		ER21-2020-000, -001; ER21-2023-000
		ER21-206-002, -003
		ER21-83-001, -002, -003; EL21-28-000
		ER25-144-000
Attachment H-10	**Public Service Electric and Gas Co.**	ER08-1233
		ER09-1257
		ER10-159
		ER10-2710
		ER11-3352-000, -001

		ER12-2274-000, -001, -002, -003
		ER12-296-002
		ER14-1608-000, -002
		ER14-621
		ER15-2397-000
		ER16-619-000
		ER19-204-000, -002
		ER20-2004-003, -004, -005, -006
		ER22-81-000
Attachment H-11	**Allegheny Power Zone**	ER10-2710-003
		ER21-253-003, -004
		ER24-1998-000
		ER24-231-001
		ER24-284-000; ER24-285-000
		ER25-19-000
Attachment H-13	**Commonwealth Edison Company**	ER10-2710-003
		ER14-1798-001
		ER15-1515-000
		ER15-959-000
		ER17-863-000
		ER19-1478-000
		ER19-5-005
		ER19-876-000
		ER20-379-000
		ER21-1292-000
		ER21-204-002, -003
		ER21-2822-000
		ER22-1082-000
		ER23-954-000
Attachment H-14 and H-20	**AEP-East Operating Companies and AEP Transmission Companies**	EL17-13-000
		EL18-62-000 et al.
		ER08-1329
		ER10-2710
		ER11-3054
		ER11-3586-000
		ER12-1255-000
		ER13-1041
		ER14-1375
		ER14-1408
		ER15-1252-000
		ER16-646-000
		ER17-405-000, -001

		ER17-406-000, -001
		ER18-1202-001
		ER18-1546-000
		ER18-2019-000
		ER18-2277-000
		ER19-2589-000
		ER19-2589-001
		ER20-1886-000, -001; ER20-1888-000, -001
		ER20-2598-000
		ER20-2598-000 Errata
		ER21-2208-000
		ER21-735-000
		ER22-1684-000
		ER23-1087-000
		ER23-852-000
		ER23-855-000
Attachment H-16	**Virginia Electric and Power Company**	EL10-49-006 et al.
		EL18-167-000
		ER08-92
		ER10-2710
		ER10-557
		ER14-1549
		ER14-1831-000, -001
		ER15-1487-000
		ER15-1504-000
		ER16-2116-001
		ER17-479-000
		ER17-714-000, -001
		ER18-1351-000
		ER18-2263-000
		ER19-1569-000
		ER19-2714-000
		ER19-839-001
		ER20-1085-000, -001, -002, -003, -004
		ER21-1680-000
		ER21-2518-000
		ER22-2443-001
		ER23-1646-000
Attachment H-17	**Duquesne Light Company**	ER10-2710-000
		ER10-2710-003
		ER10-2710-006

		ER14-1258-000
		ER20-1830-000, -001
Attachment H-18	Trans-Allegheny Interstate Line Co.	ER07-562
		ER08-958
		ER09-1151
		ER09-600
		ER10-1243
		ER10-2710
		ER11-3064-000, -001
		ER11-4574
		ER20-1829-000, -001
		ER24-1998-000
Attachment H-21	American Transmission Systems Inc. ("ATSI")	ER11-2815
		ER15-303-000, -002
		ER15-61
		ER20-1739-000, -001, -002, -003, -004
		ER20-1740-001, -002
Attachment H-28	Mid-Atlantic Interstate Transmission LLC or ("MAIT")	ER17-211-000, -001, -003, -004
		ER20-1951-000, -002, -003, -004
		ER24-1998-000
Attachment H-29 and H-30	Transource Pennsylvania LLC and Transource Maryland LLC	ER17-419-000, -001, -003, -004, -005
		ER20-2584-001, -002
		ER20-2585-001

In addition to the order in Docket No. ER10-2710 approving PJM's baseline filing containing these attachments (*see supra* text accompanying footnote 2), the FERC also approved corrections to PJM's baseline filing in Docket Nos. ER11-2801 and ER11-3057.

In Table 2 of my Schedule 2, Page 1, I show how the TEC to DOMLSE were calculated for the month of February 2025. This charge is based on the TEC (PJM OATT Schedule 12) settlement worksheet that PJM publicly posted on its website in February 2025. I have included the portion of this worksheet that shows the monthly charges and credits to the Dom Zone as Schedule 2, Pages 2-29. On Schedule 2, Page 29, I have modified this

PJM worksheet slightly by including an additional line at the bottom reading "Total TEC to the Dominion Zone," with a total amount of $29,738,334.

As a Network Customer serving load in the Dom Zone, DOMLSE is allocated a load ratio share of this total. As shown on Schedule 2, Page 1, Table 2, line 1, the application of the allocation factor to the Total TEC to the Dom Zone based on DOMLSE's megawatt ("MW") contribution to the Dom Zone Network Service Peak Load results in total TEC of $23,508,296 to DOMLSE. That charge to the DOMLSE account, in turn, is shown in line 1108 on Page 2 of Schedule 1.

As described in Schedule 12 Part e, "Crediting of Revenue from Transmission Enhancement Charges," of the PJM OATT, network customers in a Transmission Owner's Zone are allocated a share of the revenue from the Transmission Owner's TEC, provided that such amounts are reduced by any applicable incentives included in such TEC. As shown at the bottom of the Monthly Revenue Requirement column in Schedule 2, Page 10 for the Dominion RTEP projects, the total monthly revenue requirement from the Company's total TEC is $39,206,745. Carrying this amount to Column A, line 1 of Table 3 of Schedule 2, Page 1, and then subtracting from it the monthly amount of $263,951 of Transmission Enhancement incentive credit to DOMEDC (shown on line 2108, Page 17 of Schedule 1), results in $38,942,794 of monthly revenue to be allocated to the Network Customers in the Dom Zone. Applying the DOMLSE load ratio share allocation factor to this amount results in $30,784,466 being allocated to DOMLSE, which is the credit amount shown on line 2108, Page 6 of Schedule 1.

Q. Please explain the East/West Settlement.

A. On June 15, 2016, an Offer of Settlement was filed at FERC in Docket No. EL05-121-009 that addresses a dispute among numerous parties going back to 2007 as to the cost allocation of certain Regional Transmission Plan baseline reliability facilities that operate at or above 500 kilovolts ("kV"). The proposed settlement establishes a modified cost allocation for transmission projects planned to operate at or above 500 kV (including necessary supporting upgrades on lower voltage facilities) and approved by PJM's Board of Managers prior to February 1, 2013. The Settlement refers to these projects as Covered Transmission Enhancements and provides that for recovery beginning January 1, 2016, 50% of the charges for such facilities would be collected based on a load ratio share and 50% would be based on modeled power distribution over the new facility ("Solution-based DFAX"). Also, for the period of January 1, 2016, through December 31, 2025, additional "black box" settlement charges and credits would occur. The black box settlement charges and credits address the period from 2007 to January 1, 2016 (historical period) and are set forth in Schedule 12-C Appendix C of the Settlement Agreement. On May 31, 2018, the FERC issued an order ("Settlement Order") approving the settlement. The Settlement Order directed PJM to make a compliance filing in 30 days of the Order, but PJM filed for and received an extension from FERC to instead make a compliance filing on July 30, 2018 ("July 30 Compliance Filing"). PJM made a compliance filing in Docket Nos. ER18-2102-000 and ER18-2102-001.

Q. Please provide an update on the PJM Transmission Enhancement Settlement (EL05-121-009) charge to DOMLSE under the East/West Settlement.

A. The $1,071,592 monthly TEC Adjustment applicable to the Dominion Zone for Years 5 through 10 of the Settlement Agreement period, as referenced in Schedule 12-C Appendix C, commenced in January 2020. This amount, after applying the DOMLSE load ratio share allocation factor, results in the $847,098 charge to DOMLSE for February 2025, which is the Transmission Enhancement Settlement (EL05-121-009) charge amount shown on line 1115, Page 2 of Schedule 1. This charge is scheduled to terminate in December 2025 once Year 10 of Settlement Agreement period concludes.

Q. What are the costs of new facilities that the Company has projected to be added to transmission plant in-service for 2025 that were used to calculate the 2025 NITS rate?

A. The Company has projected approximately $2.194 billion of additions to transmission plant in-service that was used to calculate its 2025 NITS rate. This amount was offset by retirements and other adjustments, resulting in $2.162 billion of projected net additions to transmission plant in-service for 2025. These additions to transmission plant in-service include $1.190 billion for RTEP baseline reliability projects that are required by PJM, $742.5 million for RTEP supplemental projects, $211.5 million for reliability projects, and $50.2 million to support other FERC requirements. This last category includes $26.1 million for physical security and $3.2 million for cyber security, with the remaining $20.9 million for single point-of-failure protection and equipment changes.

Q. Please provide a brief description for each of the categories of project types that represent the projected net additions to transmission plant in-service for 2025.

A. Baseline projects include projects planned to address PJM Planning Criteria such as (i) NERC TPL-001 Standard; (ii) Operational performance identified from real time operations; or (iii) individual transmission owner criteria for high-voltage facilities operated at 500 kV and above filed on FERC Form No. 715. Supplemental Projects refer to transmission expansion or enhancements not needed to comply with PJM reliability, operational performance, individual transmission owner criteria, economic criteria, or State Agreement Approach projects. All transmission owners in PJM plan supplemental projects in accordance with the Attachment M-3 Process of the PJM OATT. Reliability projects are projects that are typically associated with specific equipment end of life, equipment failures, equipment obsolescence, and similar issues, that do not expand or enhance the transmission system and are not network upgrades as defined by PJM OATT as a baseline or supplemental projects. Lastly, other projects that support FERC requirements include transmission projects that are mandated by a FERC requirement typically associated with NERC reliability standards that are not network upgrades such as security fences, cyber security, spares and mobile equipment, and programmatic initiatives.

Q. Please provide an update on the additional transmission charge to compensate Generator Owners pursuant to Part V of the PJM OATT.

A. Briefly, Part V of the PJM OATT (approved in FERC Docket Nos. ER10-2710 and ER11-2527) sets forth procedures that allow Generator Owners to be compensated for delaying deactivation of their generating units beyond the desired deactivation dates. A

Generator Owner provides notice to PJM that it is going to deactivate a unit on a desired date, and then PJM studies the impact on the transmission system to determine if any needed transmission can be built as a result of the deactivation prior to such desired date. If needed transmission cannot be built before the desired deactivation date, and if PJM determines that it is good utility practice to pay the deactivating Generator Owner to defer its deactivation date and have its generation unit become subject to PJM's dispatch, PJM will then compensate the Generator Owner according to a formula in Part V of the PJM OATT. To provide the funds for this compensation, in accordance with Section 120 of Part V of the PJM OATT, an additional transmission charge is allocated to the load in the Zone(s) of the Transmission Owner(s) that will be assigned financial responsibility for the reliability upgrades necessary to alleviate the reliability impact that would result from the deactivation of the generating unit. This new charge is then collected monthly from such loads in addition to all other charges for transmission service to such loads.

As of the fall of 2012, the DOMLSE account was being charged as a result of the Company's financial responsibility for reliability upgrades necessary to alleviate the reliability impact resulting from the deactivation of generation units owned by FirstEnergy Generation Corporation. In accordance with the informational filings in Docket No. ER12-2710, this particular charge ended in October 2016, and the last invoiced amount is shown as an October 2016 adjustment on the PJM billing statement for November 2016. Beginning in January 2017, the Company has sought recovery of its Deactivation Avoidable Costs associated with its Yorktown Unit 1 and Yorktown Unit 2 generation facilities, as determined by its January 5, 2017 informational filing, and as revised by its June 30, 2017 informational filing, in Docket No. ER17-750-000. Because

PJM determined that reliability problems would occur if these units were retired before March 30, 2019, it allocated these deactivation avoidable costs to entities, including DOMLSE, which will also be allocated the baseline projects that are expected to relieve those reliability problems. This additional transmission charge to the DOMLSE account was shown on line 1930A of the PJM invoices and the last invoiced amount is shown as a March 2019 adjustment on the PJM billing statement for April 2019 as a result of the Yorktown Unit 1 and Yorktown Unit 2 generation facilities full deactivation. Accordingly, the amount charged to the DOMLSE account shown on line 1930 of the April 2019 PJM invoice was $93,836.

Additionally, in accordance with the Commission's directive in the Company's 2018 Rider T1 proceeding in Case No. PUR-2018-00066, as set forth in the Commission's Final Order issued August 2, 2018, the Company is including the Virginia Jurisdictional allocation of the compensation it received for delaying deactivation of the Yorktown Unit 1 and Yorktown Unit 2 generation facilities. This Generation Deactivation credit to the DOMGEN account was shown on line 2930A of the PJM invoices. As noted above, as the result of the full deactivation of the Yorktown Unit 1 and Yorktown Unit 2 generation facilities, the last credit to the DOMGEN account occurred as a March 2019 adjustment on the PJM billing statement for April 2019 shown on line 2930A in the amount of $197,969.

Q. What is FERC Order No. 1000 – Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, and how is it relevant to the determination of Subsection A 4 cost recovery?

A. Order No. 1000 establishes a number of reforms in the area of transmission planning and transmission cost allocation, and the participation of non-incumbent developers in these areas. Particularly relevant to Subsection A 4 cost recovery are the ongoing compliance efforts being made by PJM and the PJM Transmission Owners to comply with these FERC-required reforms. As demonstrated below, those efforts have been lengthy, are ongoing, and have already resulted in changes to the PJM OATT that govern regional cost allocation, or cost allocation within the PJM region, and cost allocation between the PJM region and its neighboring regions.

Q. Please identify the FERC orders pertaining to PJM-related regional compliance filings resulting from FERC Order No. 1000.

A. On March 22, 2013, FERC issued its first order conditionally accepting PJM's compliance filing in Docket Nos. ER13-198, *et al.*, which also addressed the PJM Transmission Owners' compliance filing in Docket No. ER13-90-000. The order resulted in the addition of a new Schedule 12 – Appendix A to the PJM OATT that is similar to the existing Schedule 12 – Appendix, except that it will include the RTEP projects that are to be cost-allocated in accordance with the Order No. 1000 principles for regional cost allocation approved by the FERC. Also, in Docket ER13-90-000, FERC conditionally accepted the cost allocation proposal filed by the PJM Transmission Owners that is implemented by PJM and that is effective for the allocation of RTEP baseline transmission projects approved by the PJM Board on and after the February 1, 2013 effective date. On May 15, 2014, in Docket Nos. ER13-198-001, *et al.*, FERC issued an order on rehearing and compliance. This order addresses rehearing requests in Docket Nos. ER13-198-001, ER13-195-001, and ER13-90-001, as well as compliance filings in Docket Nos. ER13-198-002 and ER13-90-002. On January 22, 2015, FERC issued an Order on Rehearing and Compliance in Docket Nos. ER13-198-003, *et al.* This particular order addresses rehearing requests in Docket Nos. ER13-198-003, ER13-195-002 and ER13-90-003, and compliance filings in Docket Nos. ER13-198-004 and ER13-90-004. Of relevance to cost allocation, this order and the compliance order in Docket Nos. ER13-198-006 and ER13-198-007 make changes to Schedule 12 of the PJM OATT so that it provides compensation to a designated entity, other than a PJM Transmission Owner, for the cost of building facilities pursuant to the RTEP.

Q. In addition to the Order No. 1000 compliance filings discussed above, please provide the dockets of the FERC-accepted, PJM-related Order No. 1000 interregional compliance filings.

A. In Docket No. ER13-1927, the FERC conditionally accepted the PJM Transmission Owners' proposed cost allocation method included in a new Schedule 12-B of the PJM OATT relating to the allocation of costs of interregional transmission system expansions and enhancements approved by PJM and participants in the Southeastern Regional Transmission Planning ("SERTP") region. On January 1, 2014, Schedule 12-B became effective subject to refund and to future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. In an order on compliance filings issued on January 23, 2015, in Docket Nos. ER13-1927, *et al.*, the FERC conditionally accepted the PJM Transmission Owners' compliance filing in Docket No. ER13-1927-000 and PJM's compliance filing in Docket No. ER13-1936-000, both of which pertain to compliance matters involving SERTP. Additional orders relating to PJM and PJM TO compliance matters involving SERTP were issued by FERC in Docket Nos ER13-1927-001, *et al.* Finally, PJM's revisions to Schedule 6-A of the Amended and Restated Operating

Agreement of PJM Interconnection, L.L.C. ("Schedule 6-A"), relating to the interregional transmission coordination procedures between PJM and the SERTP were accepted by FERC in Docket Nos. ER13-1928-007, *et al.*

In an order on compliance filings issued December 18, 2014 in Docket Nos. ER13-1944-000, *et al.*, the FERC conditionally accepted PJM's compliance filing in Docket No. ER13-1944-000 and the PJM Transmission Owners' compliance filing in Docket No. ER13-1924-000, both of which pertain to compliance matters involving MISO. Additional orders relating to PJM compliance matters involving MISO were issued by the FERC in Docket Nos. ER13-1944-001, *et al*, and Docket Nos. ER13-1944-003, *et al.* Finally, corrected tariff sheets included in the Joint Operating Agreement entered into between PJM and MISO were accepted by FERC in Docket Nos. ER13-1944-005 and -006.

In an order in Docket Nos. ER13-1957-000, *et al.*, FERC addressed numerous dockets. In two of these dockets, Docket No. ER13-1947-000 and Docket No. ER13-1926-000, FERC conditionally accepted the Order No. 1000 interregional transmission cost allocation methodology between the PJM Region and New York ISO Region that is set forth in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM, as well as the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol. In a separate order in Docket Nos. ER13-1957-000, *et al.*, FERC accepted PJM's compliance filing designating ISO New England, Inc. as the filing party for the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol.

Q. Are the interregional agreements that could result in Order No. 1000 interregional cost allocations to PJM and the Dom Zone identified in the PJM OATT, and have any of those agreements resulted in any interregional cost allocations subject to recovery under Subsection A 4 in this case?

A. Schedule 12 – Appendix B of the PJM OATT lists three such agreements. Although several interregional projects were approved by the PJM Board in 2017, no costs relating to interregional projects arising from those agreements have been allocated to the Dom Zone; therefore, there are no costs for such interregional projects subject to Subsection A 4 cost recovery in this case.

Q. Please describe the additional charge to the Company for transmission service arising from the uncontested settlement in FERC Docket No. EL10-49.

A. As a part of this settlement, Attachment H-16AA of the PJM OATT was established in FERC Docket No. ER12-1035. Attachment H-16AA contained an additional charge for transmission service referred to by Company Witness Wilkinson as the "Dominion Energy Virginia Settlement Charge" of $20,833.34 per month to be charged for 120 consecutive calendar months. Beginning on July 1, 2012, this amount was charged to the DOMLSE account on behalf of the Company's retail customers in Virginia. The funds from this charge were paid to the settling wholesale customer parties in Docket No. EL10-49 pursuant to Attachment H-16AA. After the 120 consecutive calendar months concluded on June 30, 2022, the $20,833.34 monthly settlement charge ceased to be charged to the DOMLSE account and paid to the settling wholesale customer parties, in accordance with the FERC-accepted filing made by the Company in FERC Docket No. ER22-1568-000 pursuant to Section 205 of the Federal Power Act to amend Attachment

H-16AA of the PJM OATT and replace the governing language with "Reserved for Future Use."

Q. What is the status of the incremental undergrounding costs of the three Projects that were also at issue in FERC Docket No. EL10-49?

A. In its Order on Reserved Issue on March 20, 2014, the FERC found that it is not just and reasonable to allocate the incremental costs of undergrounding the Projects to wholesale transmission customers beyond those NITS customers with Virginia loads in the Dom Zone, and ordered hearing and settlement procedures to reallocate these costs effective March 17, 2010. Specifically, at this time, hearing procedures have resulted in an initial February 2016 decision by an administrative law judge accepting the Company's proposed tariff changes (the "Initial Decision"); however, FERC's order in FERC Docket EL10-49-005 affirmed in part and reversed in part the Initial Decision. The FERC reversed the Initial Decision in regard to the calculation of the undergrounding costs and direct assignment of future capital expenditures, but affirmed the Initial Decision in regards to the allocation of the undergrounding costs and the March 17, 2010 date to start refunds. On November 20, 2017, the Company submitted its compliance filing, as well as a request for rehearing on the calculation of the undergrounding costs and direct assignment of future capital costs. Additionally, on December 15, 2017, NCEMC and ODEC filed Petitions for Review of the FERC Orders in the United States Court of Appeals for the District of Columbia. Dominion Energy Virginia intervened on January 5, 2018. The Company amended its compliance filing, and on July 5, 2018, the FERC issued an order rejecting all rehearing requests including the Company's rehearing request. However, that same order accepted the Company's compliance filing. In compliance with the order, the Company worked with PJM to issue net refunds and charges, and on October 5, 2018, it submitted a refund report to FERC. The United States Court of Appeals for the District of Columbia denied the Petitions for Review of Orders of the FERC on December 20, 2019.

Q. Please describe the PJM billing process for incremental undergrounding costs of the three Projects.

A. In Table 1A of Schedule 2, Page 1, I show how the Underground Transmission Service Charge to the DOMLSE account is calculated for the month of February 2025. The annual rate used to calculate this charge is from the Company's January 15, 2025 Information Filing in FERC Docket No. ER09-545 and is the $541.18/MW/year amount shown on line 1 of Table 1A. Line 2 divides this amount to convert it to a MW/day rate and line 3 applies this daily rate to DOMLSE's Virginia MW days in February. I refer to this as Virginia MW days because it excludes DOMLSE's MW days attributed to its load in its North Carolina service territory.

Accordingly, the $739,627 amount shown on line 4 of this Table 1A of Schedule 2 is the same amount shown on Schedule 1, Page 2, line 1103 of the February 2025 bill to the DOMLSE account.

Q. Please describe the Company's proposed revisions to certain components of its formula rate within Attachment H-16A as filed in FERC Docket No. ER19-2714 charge.

A. On August 30, 2019, the Company filed with FERC seeking to revise Attachment H-16A to incorporate a new attachment (Attachment 11 and Attachment 11A) that will allocate the capital costs associated with the Company acquiring Allegheny Generating Company's ("AGC") 40 percent undivided ownership in the (1) Bath-Valley 500 kV transmission line; (2) Bath-Lexington 500 kV transmission line; and (3) the transmission facilities within the Bath County Facility Substation (collectively, the "Bath Transmission Facilities"). The Company owned the remaining 60 percent in the Bath Transmission Facilities. To maintain the historical allocation of costs, the Company prepared a new attachment to calculate the full amount of capital costs for the Bath Transmission Facilities in the determination of the annual revenue requirement for the Dom Zone, but 40 percent of those costs will be allocated and billed by PJM to AGC's transmission owner within the Allegheny transmission zone. FERC approved the proposed revisions on October 28, 2019.

Q. Did the Company seek appropriate regulatory approval of the transfer of undivided ownership and did the transaction consummate?

A. Yes, it did. On August 30, 2019, the Company and AGC filed a Section 203 application with the FERC, in FERC Docket No. EC19-132-000, requesting authorization for a transaction whereby the Company will acquire AGC's interest in the Bath Transmission Facilities located in Virginia. FERC approved and authorized the transaction on November 7, 2019. In addition, the Company and AGC filed a joint petition with the Commission, in Case No. PUR-2019-00052, for approvals related to the Company's acquisition of AGC's 40 percent undivided ownership in the Bath Transmission Facilities. This Commission issued an order granting approval on July 19, 2019. The transaction was consummated on November 15, 2019.

Q. Will transmission customers within the Dom Zone be responsible for the new costs of now owning 100% of the Bath Transmission Facilities?

A. In order to consolidate ownership in which the Company will now own 100 percent of the Bath Transmission Facilities, while maintaining the historic allocation of costs, the new attachment establishes a revenue requirement for which an adjustment factor of 40 percent is applied to develop the capital investment revenue requirement for the AGC's previous 40 percent ownership share of the Bath Transmission Facilities. This amount is then applied as a revenue credit against the Company's total transmission revenue requirement, ensuring that the Company's transmission customers pay only the 60 percent share of the Bath Transmission Facilities' costs, as they have done prior to the transaction.

Q. Please describe how these cost credits are shown on the PJM invoice for DOMEDC.

A. The DOMEDC account receives credits from PJM for the previous 40 percent ownership share of the Bath Transmission Facilities in the amount of $231,203 as shown on line 2110 (Direct Assignment Facilities) of Schedule 1, Page 17. PJM pulls this amount from the Company's Attachment 11 of its Attachment H-16A.

Q. Please describe the PJM administrative charge and the related billing process for that charge.

A. The PJM administrative charge is recovered through various rates for the multiple services provided to the RTO's market participants, including the Company. The detailed administrative charges are shown in the monthly PJM invoice for February 2025 provided as Schedule 1. The charges and credits to the DOMLSE account are shown in lines 1301 through 1319 and lines 1440 through 1449 on Pages 2-4 of Schedule 1.

Likewise, the charges to the DOMGEN account are shown in lines 1301 through 1314 on Page 9 of Schedule 1. Notably, in some months, there are adjustments to some of these charges, as indicated on the PJM invoice by the letter "A" after a particular line number. Just prior to January 1, 2018, the administrative costs of operating PJM were recovered in PJM OATT Schedules 9-1 through 9-6, which were modified by a settlement agreement in FERC Docket No. ER05-1181, and otherwise accepted in FERC Docket Nos. ER04-548, EL06-55, EL05-148, ER05-1410, ER10-478, ER10-893, ER10-2710, ER11-4174, ER13-1166, and ER13-1654. Additionally, other administrative charges included in the PJM OATT have been approved by the FERC and provide funding for the Market Monitoring Unit (Schedule 9-MMU), the FERC itself (Schedule 9-FERC), the Organization of PJM States, Inc. (Schedule 9-OPSI), the Finance Committee Retained Consultant (Schedule 9-FINCON), PJM Settlement, Inc. (Schedule 9-PJMSettlement), and Consumer Advocates of PJM States, Inc. Funding (Schedule 9-CAPS).

The rates charged to PJM market participants, including the Company, are based on billing determinants reflecting the individual services provided. The rates for Schedules 9-1 through 9-5 were defined in these schedules; however, as a result of PJM's proposed OATT revisions in FERC Docket No. ER22-26 that became effective January 1, 2022, the rates for Schedules 9-1 through 9-4 are defined in these schedules, having removed Schedule 9-5. Prior to January 1, 2022, the revenues collected under the rates defined in these schedules that were in excess of PJM's expenses, plus a 6% reserve, were refunded. In accordance with the first amendment to the settlement agreement in Docket No. ER05-1181, which the FERC permitted to become effective on April 1, 2008, in Docket No. ER08-528, such refunds were determined and refunded quarterly rather than annually.

The rates at issue are reviewed by both the PJM Finance Committee and the PJM Members Committee and are described in more detail below. To the extent that administrative fees are billed based on previous scheduled usage, such usage is reconciled to actual usage based on metered data, and a credit or charge reflecting this reconciliation is shown on the monthly PJM billing statements.

Beginning October 1, 2011, the stated rates for Schedules 9-1 through 9-5 decreased by approximately 3.3% as a result of a filing that PJM made in Docket No. ER11-4174 to change rates to reflect the integration of American Transmission Systems, Inc. ("ATSI") and ATSI utilities – namely, Cleveland Electric Illuminating Company, Ohio Edison Company, Toledo Edison Company, and Pennsylvania Power Company, as well as ATSI's generation affiliate, FirstEnergy Solutions – into PJM effective June 1, 2011. In Docket No. ER17-249-000, FERC accepted PJM's proposal to eliminate Schedule 9-6 and increase the stated rates in Schedules 9-1 through 9-5. A portion of this increase recovers PJM's actual capital and operating costs for its Advanced Second Control Center that used to be recovered by the formula rate in Schedule 9-6. The stated rates became effective on January 1, 2017, and were set forth in the schedules. The rates were shown as commencing on January 1 of each year during 2017 through 2024.

Additionally, Schedule 9 included a table that showed how refunds were to be allocated to each of the Schedules 9-1 through 9-5. Generally, the refunds were made quarterly when Schedule 9-1 through 9-5 revenues were sufficient to recover costs and meet PJM's 6% of projected annual revenues during the calendar year reserve requirement. However, once every third year, the reserve was reduced to 2% of the projected annual revenues in order to minimize income tax expense to its members. Also, to the extent the reserve falls below 2%, there was a provision requiring PJM to consult with the Finance Committee and develop a plan to restore the reserve. The FERC order in Docket Nos. ER18-1905 and -001 accepted PJM's revisions of non-substantive, clerical, and ministerial changes to correct, clarify, and/or make consistent certain provisions contained in this schedule. Nevertheless, the table was removed pursuant to the FERC order in Docket No. ER21-274.

As of January 1, 2022, the admistrative costs of operating PJM are recovered in PJM OATT Schedules 9-1 through 9-4, as the OATT revisions proposed by PJM on October 1, 2021, in Docket No. ER22-26 were accepted but suspended by FERC for a nominal period which became effective January 1, 2022, subject to refund and establishing hearing and settlement judge procedures. The currently effective OATT revisions proposed by PJM serve to transition the calculation of administrative costs from a stated rate to a formula rate that determines each service category's rate each month by dividing the actual costs for that month by the billing determinants for that month. Under the currently effective OATT, two service categories (Market Support Service and Regulation and Frequency Response Administration Service) were consolidated into a single service category under Schedule 9-3. Furthermore, under the proposed OATT revisions, the 6% reserve was eliminated, and the entire reserve amount was refunded to PJM market participants over the first three months of 2022. The proposed changes also require PJM to provide the Finance Committee with five-year projections of the rates for Schedules 9-1 through 9-4, Schedule 9-PJMSettlement, information on the assignments of projected capital expenses to the service categories, advance notice of material changes to PJM's services, and an updated cost of service study every five years to inform PJM market participants on the possible need for changes to the cost assignment and allocation percentages. Additionally, PJM changed the methodology for determining the Schedule 9-PJMSettlement charge by basing the amount on the number of invoices issued for a customer in a given month. Lastly, PJM added stated percentage values to the OATT to assign PJM's costs among the administrative service categories.

As part of the hearing and settlement judge procedures established by FERC in Docket No. ER22-26 described above, on March 31, 2022, PJM filed a Settlement Agreement and Offer of Settlement ("Schedule 9 Settlement") by and among PJM, Old Dominion Electric Cooperative, DC Energy, LLC, Exelon Corporation, and the PJM Industrial Customer Coalition (the "Settling Parties") that addressed proposed revisions to PJM OATT, Schedule 9-PJM Settlement, including, among other revisions, a proposal to change the billing determinants for Tariff Schedule 9-2, Market Administration Service, to a new billing determinant based on the number of invoices issued by PJM. On November 9, 2022, FERC issued a letter order approving the Schedule 9 Settlement and directed PJM to make a compliance filing within 30 days of the date of the letter order. On December 8, 2022, PJM submitted its compliance filing in satisfaction of the directives of the November 9 Order. As part of the Schedule 9 Settlement, the Settling Parties agreed to amend Schedule 9-PJMSettlement, PJM Settlement, Inc. Administrative Services, to provide that PJM Settlement, Inc. shall recover 68% of its costs on a per-invoice basis, and 32% of its costs further divided into four equal sub-components (and then broken into six different sub-rates) and recovered using the same billing determinants used in OATT, Schedules 9-1 through 9-4. FERC accepted PJM's compliance filing on February 9, 2023, with the OATT revisions becoming effective on

February 1, 2023.

Consistent with the Commission's Final Order in the 2009 Rider T Case, the Company is seeking recovery of only certain PJM-related administrative charges in this proceeding. I will now describe in more detail the current administrative charges in Schedules 9-1 and 9-2 for which the Company is seeking recovery under Subsection A 4, and Company Witness Wilkinson will discuss the calculations of these charges in the revenue requirement that he presents in his direct testimony.

Schedule 9-1, Control Area Administration Service

The Monthly Control Area Administrative Service Rate recovers the costs of all PJM activities associated with preserving the reliability of the PJM Region, and with administering Point-to-Point Transmission Service and NITS. The rates set forth in this schedule and charged to transmission customers are based on their usage of the PJM transmission system. Monthly transmission use in MWh includes the total quantity in MWh of energy delivered (including losses) during such month by such user as a transmission customer under the PJM Tariff for Point-to-Point Transmission Service or NITS. Restated rates for this schedule were approved in FERC Docket No. ER10-478, and PJM's baseline filing that included this schedule was approved in FERC Docket No. ER10-2710. Lower rates for this schedule were approved in FERC Docket No. ER11-4174 that became effective October 1, 2011. As discussed above, this schedule, as of the January 1, 2017 effective date, reflected the increase in rates approved in FERC Docket No. ER17-249-000. In FERC Docket No. ER19-469-002, PJM made revisions of non-substantive, clerical, and ministerial changes to correct, clarify, and/or make consistent certain provisions contained in this Schedule 9-1. In FERC Docket No. ER22-26, and as currently effective as of January 1, 2022, this schedule was amended to include a formula for determination of the rate based on the costs incurred each month, where the actual costs assigned to the Control Area Administration Service is divided by the actual total quantity of MWh of energy delivered under Point-to-Point Transmission Service or NITS.

<u>Schedule 9-2, Financial Transmission Rights ("FTR") Administration Service</u>

The FTR Service Rate recovers the costs of all PJM activities associated with administering the FTRs provided for under Attachment K to the PJM OATT. These activities include, but are not limited to, coordination of FTR bilateral trading; administration of FTR auctions; support of PJM's Internet-based eFTR reporting tool; and analyses to determine what total combination of FTRs can be outstanding and accommodated by the PJM system at any given time. Simply put, PJM provides this service to entities, like the Company, that hold FTRs, or that submit offers to sell or bids to buy FTRs.

On a monthly basis, users of Financial Transmission Rights Administrative Service were charged (i) the FTR Service Rate, Component 1 times the FTR holders total FTRs in megawatt-hours during such month plus (ii) the FTR Service Rate, Component 2 times the sum of (1) number of hours submitted in all bids to buy FTR obligations, plus (2) a factor of five times the number of hours submitted in all bids to buy FTR options. Restated rates for this schedule were approved in FERC Docket No. ER10-478, and PJM's baseline filing including this schedule was approved in FERC Docket No. ER10-2710. Lower rates for this schedule were approved in FERC Docket No. ER11-4174, which became effective October 1, 2011. As discussed above, this schedule, as of the

January 1, 2017 effective date, reflected the increase in rates approved in FERC Docket No. ER17-249-000. Also, in FERC Docket Nos. ER17-1372-000, and ER18-1905-000 and -001, clarifying language changes were made to this schedule. The OATT revisions proposed by PJM in FERC Docket No. ER22-26 on October 1, 2021, incorporate into this schedule a formula for Financial Transmission Rights Administrative Service. This schedule bifurcates the Financial Transmission Rights Administrative Service into two components, where Component 1 represents the monthly FTR MWh costs divided by the monthly FTR MWh determinants, and Component 2 represents the monthly FTR bid/offer hours cost divided by the monthly FTR Bid/Offer Hours Determinants.

Q. Please describe the October 2021 FERC order (Docket No. ER22-26) accepting the proposed tariff revisions related to PJM's revisions to administrative costs recovery charges.

A. PJM's revisions to the administrative cost recovery charges included, among other revisions, reducing the five Service Categories of unbundled PJM administrative services to four Service Categories. After PJM's consultation with a third-party consulting firm, it was concluded that combining Market Support Services (previously Schedule 9-3) and Regulation and Frequency Response Administrative Services (previously Schedule 9-4) would better align with the services that PJM provides its membership. PJM adopted this change in the ER22-26 proceeding citing three main supporting factors for combining Schedules 9-3 and 9-4.

First, Market Support Service already recovers the costs of PJM's administration of other ancillary services. Regulation and Frequency Response is the only ancillary service that currently has its own separate PJM administrative Service Category. Only a very small share of PJM's costs (less than 2%) is directly assigned to Schedule 9-4.

Second, the beneficiaries of both Service Categories (Regulation and Frequency Response Administration Service and of Market Support Service) are the same. Load serving entities purchase energy and ancillary services (which PJM administers under Schedule 9-3) and use regulation and frequency response services (which PJM administers under Schedule 9-4). At the same time, generators both sell energy and ancillary services using the administrative services PJM provides under Schedule 9-3, and generators provide regulation and frequency response services using the administrative services PJM provides under Schedule 9-4.

Third, the activities performed by PJM to provide Regulation and Frequency Response Administration Service are performed by the same people and systems that administer other ancillary services provided under Schedule 9-3.

Q. How do the changes in FERC Docket No. ER22-26 impact the "administrative charges" for which the Company intends to recover the costs through Subsection A 4?

A. Prior to PJM's proposed change to combine Schedule 9-3 and 9-4 in FERC Docket No. ER22-26 which became effective January 1, 2022, the Company requested and received approval to recover Schedules 9-1, 9-2, and 9-4, and has been doing so since the 2009 Rider T Case. Since PJM has combined Schedules 9-3 and 9-4, it is now infeasible for the Company or PJM to identify what specific costs are directly related to "Regulation and Frequency Response Administration Service" previously recovered in Schedule 9-4. Therefore, in the 2022 Rider T1 Case, the Company no longer sought to recover via

Rider T1 the costs related to the Regulation and Frequency Response Administration Service, as they are now combined with Market Support Services. Previously included in Schedule 9-3, Market Support Service is a PJM-related administrative charge that was not approved as a recoverable expense in any of the previous Rider T proceedings. As the Market Support Services charges are now bundled in Schedule 9-3 in conjunction with the Regulation and Frequency Response Administration Service charges that were previously included in Schedule 9-4, the related costs are no longer being recovered by the Company in Rider T1, consistent with the Rider T1 Cases since 2022.

Q. Please describe the PJM demand response programs and the related billing process for the costs of these programs.

A. The Economic Load Response Program and Emergency and Pre-Emergency Load Response Program charges are costs for the demand response programs approved by FERC and administered by PJM. These programs function as a means for participants to receive payments for reducing load. The Economic Load Response Program allows qualifying entities to participate in the PJM markets by submitting bids to reduce demand and to receive payments for their voluntary load reductions. Generally, these payments are based on the Locational Marginal Prices ("LMPs") in PJM's Day-Ahead Energy Market and Real-Time Energy Market.

More specifically, effective April 1, 2012, in accordance with the FERC's orders accepting a series of PJM compliance filings in Docket Nos. ER11-4106-000, ER11-4106-001, ER11-4106-002, ER11-4106-003, ER11-4106-004, ER12-1705, and ER15-1849, when payment of LMP is cost-effective, as determined by a net benefits test prescribed by FERC Order Nos. 745 and 745-A,[7] payments to the participant are based on the LMP, and the cost of such payments is distributed to those loads that benefit from the demand reduction. The net benefits test establishes a threshold price so that when LMPs are equal to or higher than the threshold price, payments based on LMPs are determined to be cost-effective; and, when LMP is less than the threshold price, payments are zero. The cost of the payments for the demand reductions is charged to those loads and exports in each zone for which the load weighted average LMP for the hour during which such load reduction occurred is greater than the threshold (net benefits test) price. Thus, when the Company is determined to be a beneficiary through the application of the net benefits test, it is charged by PJM for demand reductions under the Economic Load Response Program. For example, these charges to the DOMLSE account for February 2025 are shown in lines 1242 and 1243 on Page 2 of Schedule 1.

The Emergency and Pre-Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency or pre-emergency event, and is comprised of two Load Management Program options – the Full Program Option and the Capacity Only Option. Both options allow participants to receive capacity payments for their Load Management Resources. Under both of these programs, curtailments are mandatory during emergencies, pre-emergencies, and tests. Participants are subject to penalties for noncompliance. In addition to the capacity payment, under the Full Program Option, participants also receive an energy payment during emergencies or pre-emergencies. The

[7] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187, *reh'g denied*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012).

energy payment under this option is the LMP, but the total payments during an emergency or pre-emergency are subject to a minimum amount, including a minimum dispatch price and shut down costs, which can result in compensation much higher than the LMP. This compensation in excess of the LMP is paid to the provider and allocated among PJM market participants in proportion to the net increased purchases or decreased sales in the Real-Time Energy Market during the emergency event, as compared to their positions in the Day-Ahead Energy Market.

Effective February 1, 2012, and in accordance with FERC's orders in Docket Nos. ER12-525-000 and ER12-525-001, real-time dispatch reduction MWh were subtracted from the purchases to determine the net increased purchases for the purpose of allocating the cost of the energy payment. This change removed a disincentive that a net purchaser might have to follow PJM's dispatch instructions to reduce MWh in real-time supplied from its resource during a PJM emergency event. In other words, without this change, a market purchaser with a resource that followed PJM's dispatch instruction to reduce the number of MW supplied in real-time during an emergency would have faced an allocation of emergency-related costs if, by following PJM's dispatch instruction, it increased the market purchaser's net purchases in the Real-Time Energy Market as compared to the Day-Ahead Energy Market.

In addition to the two Load Management options discussed above, there is an Energy Only option, which is also part of the Emergency and Pre-Emergency Load Response Program but is not commonly used. It is similar to the Economic Load Response Program in that curtailment is voluntary and no capacity payment is involved. However, unlike the Economic Load Response Option, the energy compensation is the same as that discussed above for the Full Program Option and is available only during emergencies.

The FERC approved the Economic Load Response Program in Docket No. ER02-1326, as modified in Docket Nos. ER06-406, ER08-841, ER08-824, ER08-780, ER09-701, ER09-1508, ER10-893, ER10-2710, ER11-2074, ER11-2527, ER12-4106-000, -001, -002, -003, and -004, ER12-1705, ER13-1353, ER15-1849, ER16-873, ER17-1372-000, ER17-775-000, -001, -002, -003, and -004, ER18-1528-000, ER19-744-000, ER19-1694-000, EL19-58-006, and ER24-1987-000. Additionally, FERC approved the Emergency and Pre-Emergency Load Response Program in FERC Docket No. ER02-1205, as modified in Docket Nos. ER06-406, ER05-1410, EL05-148, ER09-701, ER09-797, ER09-1063-000 and -004, ER09-1508, ER10-2710, ER11-2527, ER11-2898, ER11-3322, ER12-525-000 and -001, ER12-2262-000 and -001, ER12-1372, ER13-1353, ER14-822, ER15-1849-000, ER16-873-000, ER14-822-022 and -003, ER16-1520-000, and ER16-2460-000, and ER17-1372-000, and ER17-775-000, -001, -002, -003, and -004, ER19-744-000, ER19-244-000, ER19-1694-000, ER20-1590-000, ER23-725-000, and ER24-1987-000. While these programs were initially set up to be temporary, subsequent FERC orders in Docket No. ER06-406 removed their termination dates. The costs associated with these demand response programs are determined in accordance with Section 3.3A Economic Load Response Participants of Attachment K-Appendix of the PJM OATT, and Appendix Section 8 of that same attachment (labeled "Emergency and Pre-Emergency Load Response Program"). Additionally, more information regarding the costs to the Company of these programs are the PJM Load Response Charges referenced in PJM Manual 29: Billing, Section 2: Monthly Billing Statement, and are described in detail in PJM Manual 28: Operating Agreement Accounting, Section 11: PJM Load

Response Programs Accounting.[8]

Q. Please briefly explain the interconnection agreement arrangement between the Company and PEPCO that resulted in the establishment of the PEPDVP account, as well as the Subsection A 4 costs that were included in that account.

A. This was essentially an arrangement that allowed both PEPCO and the Company to serve some of their retail loads by using the transmission facilities of the other company pursuant to a "wires to wires" interconnection agreement (Service Agreement No. 3657) that the FERC accepted in Docket No. ER14-269. The settlement of this arrangement was done on a net basis through the PEPDVP account. Because the Dominion Energy Virginia retail loads served under this arrangement were larger than the PEPCO retail loads, there were net PJM charges to the Company for the wholesale loads served by PEPCO facilities – and some of those charges and credits were Subsection A 4 costs. Those charges and credits were included in the same categories of charges and credits that I identified above for the DOMLSE account. For example, one of the largest of these Subsection A 4 charges to the PEPDVP account for February 2024 was the NITS charge amount of $2,366 shown on line 1100 of Schedule 1, Page 24 in the 2024 Rider T1 Case. The NITS charge to PEPDVP was determined similarly to the NITS charge to DOMLSE, except that the NITS rate was based on the PEPCO Attachment H-9A to the PJM Tariff. This attachment was part of the FERC-approved PJM baseline tariff and modifications discussed above and was modified in Docket Nos. ER13-607-003, ER15-1374, ER16-456-001 and -002, etc. as referenced in Table 2 herein.

[8] *See* http://www.pjm.com/library.aspx.

Due to the discontinuation of two interconnection points ("Georgetown C – Rosslyn 13.8 kV Interconnection Point #1" and "Georgetown C – Rosslyn 13.8 kV Interconnection Point #2," collectively, "Rosslyn Interconnection Points") within the interconnection agreement that precipitated the establishment of the PEPDVP account, as of June 2024, the PEPDVP account was terminated. Dominion identified a project need that will allow it to meet service obligations to its retail customers without the need for the connection with PEPCO and thus requiring the removal of the Rosslyn Interconnection Points. Effective June 18, 2024, Dominion disconnected from the Rosslyn Interconnection Points; therefore, the PJM charges and credits to the Company for the wholesale loads served by PEPCO facilities have generally ceased with the exception of nominal, ongoing PJM billing adjustments and administrative charges which could continue for up to two years following the termination of the PEPDVP account.[9] In light of the termination of the PEPDVP account, and due to the de minimis amount of the ongoing charges, the Company is not seeking recovery of the PEPDVP charges in this Rider T1 proceeding.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

[9] PJM OATT, Section I.10.4.

BACKGROUND AND QUALIFICATIONS OF MICHAEL J. BATTA

Michael J. Batta received a Bachelor of Science degree in Finance from Virginia Commonwealth University in 1996, and a Master of Business degree from The College of William & Mary in 2004. In 1996, he worked as a financial analyst for the Federal Reserve Bank of Richmond. He joined the Company in 2001, and held positions as Supervisor of Market Origination Support, Manager of Commodity Trading Financial Support, Senior Electric Market Policy Manager. In 2013, Mr. Batta was promoted to the role of Director Electric Transmission, Market, and FERC Policy and in June 2025 he transitioned to his current role as Senior Strategic Advisor on FERC Policy

Mr. Batta has previously submitted testimony before the State Corporation Commission of Virginia and the Federal Energy Regulatory Commission.

pjm Settlement

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

INVOICE NUMBER:	2025022810964	
CUSTOMER ACCOUNT:	Dominion Virginia Power (LSE)	
CUSTOMER IDENTIFIERS:	DOMLSE (10964)	
FINAL BILLING STATEMENT ISSUED:	03/07/2025 08:31:24	
BILLING PERIOD:	02/01/2025 to 02/28/2025	
Monthly Billing Total:		$91,158,086.73
Previous Weekly Billing Total:		$81,697,804.40

Monthly Billing Statement Summary	Total
Total Net Charge. Please Pay This Amount.	$9,460,282.33

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 2025-03-14

Fed Wire/ACH Bank Instructions: [redacted]

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

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Stephen Lawson
President

pjm Settlement

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power (LSE)

CUSTOMER IDENTIFIERS DOMLSE

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$106,371,492.03
1103		Underground Transmission Service		$739,627.45
1108		Transmission Enhancement		$23,508,295.78
1115		Transmission Enhancement Settlement (EL05-121-009)		$847,098.39
1120		Other Supporting Facilities		$50,199.60
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		($1,939.50)
1205		Balancing Spot Market Energy		($4,718,852.25)
1210		Day-ahead Transmission Congestion		($336.32)
1215		Balancing Transmission Congestion		($71,551.11)
1220		Day-ahead Transmission Losses		($76.23)
1225		Balancing Transmission Losses		($51,984.00)
1230		Inadvertent Interchange		($97,052.04)
1242		Day-Ahead Load Response Charge Allocation		$30,154.43
1243		Real-Time Load Response Charge Allocation		($1,979.66)
1250		Meter Error Correction		($154.44)
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$2,077,348.67

PJM Settlement, Inc.
2750 Monroe Blvd.
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CUSTOMER ACCOUNT: Dominion Virginia Power (LSE)

CUSTOMER IDENTIFIERS DOMLSE

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

1302	PJM Scheduling, System Control and Dispatch Service - FTR Administration	$15,036.14
1303	PJM Scheduling, System Control and Dispatch Service - Market Support	$336,500.62
1305	PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.	$0.00
1313	PJM Settlement, Inc.	$19,150.02
1314	Market Monitoring Unit (MMU) Funding	$64,911.92
1315	FERC Annual Recovery	$1,005,278.64
1316	Organization of PJM States, Inc. (OPSI) Funding	$10,547.72
1319	Consumer Advocates of PJM States, Inc. (CAPS)	$5,679.54
1320	Transmission Owner Scheduling, System Control and Dispatch Service	$0.00
1330	Reactive Supply and Voltage Control from Generation and Other Sources Service	$3,043,278.33
1340	Regulation and Frequency Response Service	($46,280.96)
1360	Synchronized Reserve	$717,524.01
1361	Secondary Reserve	$17,586.98
1362	Non-Synchronized Reserve	$62,590.49
1370	Day-ahead Operating Reserve	$260,357.25
1375	Balancing Operating Reserve	$2,415,089.80
1376	Balancing Operating Reserve for Load Response	($0.03)
1380	Black Start Service	$281,878.60
1400	Load Reconciliation for Spot Market Energy	$1,181,865.18

PJM Settlement, Inc.
2750 Monroe Blvd.
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CUSTOMER IDENTIFIERS DOMLSE

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

1410		Load Reconciliation for Transmission Congestion		$130,295.13
1420		Load Reconciliation for Transmission Losses		$29,906.70
1430		Load Reconciliation for Inadvertent Interchange		($0.69)
1440		Load Reconciliation for PJM Scheduling, System Control and Dispatch Service		$12,389.65
1443		Load Reconciliation for PJM Settlement, Inc.		$105.21
1444		Load Reconciliation for Market Monitoring Unit (MMU) Funding		$288.94
1445		Load Reconciliation for FERC Annual Recovery		$5,478.29
1446		Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding		$48.84
1449		Load Reconciliation for Consumer Advocates of PJM States, Inc. (CAPS) Funding		$24.42
1460		Load Reconciliation for Regulation and Frequency Response Service		$7,811.33
1470		Load Reconciliation for Synchronized Reserve		$1,857.80
1471		Load Reconciliation for Secondary Reserve		$50.23
1472		Load Reconciliation for Non-Synchronized Reserve		$397.71
1478		Load Reconciliation for Balancing Operating Reserve		$1,689.38
1500		Financial Transmission Rights Auction		$25,502,252.72
1243	A	Real-Time Load Response Charge Allocation	01/01/2025	($8.44)
1250	A	Meter Error Correction	01/01/2025	($10,884.52)
1340	A	Regulation and Frequency Response Service	11/01/2024	$197.47
1340	A	Regulation and Frequency Response Service	01/01/2025	$134.99

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CUSTOMER IDENTIFIERS DOMLSE

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

1360	A	Synchronized Reserve	10/01/2024	($12.86)
1360	A	Synchronized Reserve	01/01/2025	$4.64
1361	A	Secondary Reserve	10/01/2024	($618.25)
1362	A	Non-Synchronized Reserve	10/01/2024	($1,703.94)
1375	A	Balancing Operating Reserve	02/01/2023	$0.01
1375	A	Balancing Operating Reserve	07/01/2023	$3.98
1375	A	Balancing Operating Reserve	10/01/2023	$17.51
1375	A	Balancing Operating Reserve	12/01/2023	$673.08
1375	A	Balancing Operating Reserve	03/01/2024	$8.87
1375	A	Balancing Operating Reserve	04/01/2024	($1,482.50)
1375	A	Balancing Operating Reserve	05/01/2024	$462.88
1375	A	Balancing Operating Reserve	10/01/2024	($301.79)
1375	A	Balancing Operating Reserve	11/01/2024	($2,135.44)
1375	A	Balancing Operating Reserve	01/01/2025	$7,667.66
1376	A	Balancing Operating Reserve for Load Response	01/01/2025	$0.01
1380	A	Black Start Service	08/01/2024	$523.28

Total Charges: **$163,756,427.35**

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power (LSE)

CUSTOMER IDENTIFIERS DOMLSE

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2108		Transmission Enhancement		$30,784,466.05
2130		Firm Point-to-Point Transmission Service		$1,815,250.94
2140		Non-Firm Point-to-Point Transmission Service		$215,333.27
2211		Day-ahead Transmission Congestion		$8,947,219.91
2215		Balancing Transmission Congestion		($3,614,743.90)
2220		Transmission Losses		$4,799,943.48
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Balancing Synchronized Reserve		$0.00
2361		Balancing Secondary Reserve		$0.00
2366		Day-ahead Synchronized Reserve		$0.00
2367		Day-ahead Secondary Reserve		$0.00
2368		Day-ahead Non-Synchronized Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00

PJM Settlement, Inc.
2750 Monroe Blvd.
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CUSTOMER ACCOUNT: Dominion Virginia Power (LSE)

CUSTOMER IDENTIFIERS DOMLSE

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

2415		Balancing Transmission Congestion Load Reconciliation		($14,803.96)
2420		Load Reconciliation for Transmission Losses		$17,292.62
2500		Financial Transmission Rights Auction		$235,509.12
2510		Auction Revenue Rights		$29,266,851.28
2640		Incremental Capacity Transfer Rights		$141,785.31
2140	A	Non-Firm Point-to-Point Transmission Service	01/01/2025	$831.69
2211	A	Day-ahead Transmission Congestion	12/01/2024	$0.02
2211	A	Day-ahead Transmission Congestion	01/01/2025	($0.01)
2390	A	Fuel Cost Policy Penalty	01/01/2025	$3,526.45
2640	A	Incremental Capacity Transfer Rights	01/01/2025	($121.65)

Total Credits: **$72,598,340.62**

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

INVOICE NUMBER:	2025022800071	
CUSTOMER ACCOUNT:	Dominion Virginia Power	
CUSTOMER IDENTIFIERS:	DOMGEN (71)	
FINAL BILLING STATEMENT ISSUED:	03/07/2025 08:31:24	
BILLING PERIOD:	02/01/2025 to 02/28/2025	
Monthly Billing Total:		$79,213,940.47
Previous Weekly Billing Total:		$84,416,824.78

Monthly Billing Statement Summary	Total
Total Net Credit to You. Please Do Not Pay	$5,202,884.31

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 2025-03-14

Fed Wire/ACH Bank Instructions: [redacted]

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

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Stephen Lawson
President

pjm Settlement

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2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power

CUSTOMER IDENTIFIERS DOMGEN

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1120		Other Supporting Facilities		$46,054.82
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$62,692,232.57
1205		Balancing Spot Market Energy		$968,351.84
1210		Day-ahead Transmission Congestion		$9,673,217.09
1215		Balancing Transmission Congestion		($155,686.86)
1220		Day-ahead Transmission Losses		$11,910,557.87
1225		Balancing Transmission Losses		$98,687.83
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$284,852.35
1305		PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$201,760.21
1313		PJM Settlement, Inc.		$16,708.48
1314		Market Monitoring Unit (MMU) Funding		$54,971.75
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power

CUSTOMER IDENTIFIERS DOMGEN

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

1340		Regulation and Frequency Response Service		$1,956,389.73
1360		Synchronized Reserve		$2,242.79
1361		Secondary Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$146,264.08
1376		Balancing Operating Reserve for Load Response		($0.05)
1380		Black Start Service		$0.00
1681		FRR LSE Capacity Resource Deficiency		$981,048.32
1140	A	Non-Firm Point-to-Point Transmission Service	01/01/2025	$2,278.88
1340	A	Regulation and Frequency Response Service	11/01/2024	$2.99
1340	A	Regulation and Frequency Response Service	01/01/2025	$10.40
1375	A	Balancing Operating Reserve	02/01/2023	$0.01
1375	A	Balancing Operating Reserve	07/01/2023	$18.72
1375	A	Balancing Operating Reserve	10/01/2023	$9.00
1375	A	Balancing Operating Reserve	12/01/2023	$1,505.81
1375	A	Balancing Operating Reserve	03/01/2024	$5.33
1375	A	Balancing Operating Reserve	04/01/2024	($1,041.10)
1375	A	Balancing Operating Reserve	05/01/2024	$679.39
1375	A	Balancing Operating Reserve	10/01/2024	($184.22)

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power

CUSTOMER IDENTIFIERS DOMGEN

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

1375	A	Balancing Operating Reserve	11/01/2024	($372.17)
1375	A	Balancing Operating Reserve	01/01/2025	$8,353.42
1376	A	Balancing Operating Reserve for Load Response	01/01/2025	$0.02

Total Charges: **$88,888,919.30**

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power

CUSTOMER IDENTIFIERS DOMGEN

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$2,537,500.00
2340		Regulation and Frequency Response Service		$2,724,540.01
2360		Balancing Synchronized Reserve		$135,557.89
2361		Balancing Secondary Reserve		$13,534.49
2362		Balancing Non-Synchronized Reserve		($98,397.38)
2366		Day-ahead Synchronized Reserve		$369,397.58
2367		Day-ahead Secondary Reserve		$0.00
2368		Day-ahead Non-Synchronized Reserve		$24,052.62
2370		Day-ahead Operating Reserve		$10,362.60
2375		Balancing Operating Reserve		$3,610,198.03
2380		Black Start Service		$349,172.55
2361	A	Balancing Secondary Reserve	10/01/2024	($1,924.10)
2362	A	Balancing Non-Synchronized Reserve	10/01/2024	($1,462.68)

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power

CUSTOMER IDENTIFIERS DOMGEN

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

2375	A	Balancing Operating Reserve	07/01/2023	$1,138.55
2375	A	Balancing Operating Reserve	08/01/2024	$698.53
2375	A	Balancing Operating Reserve	10/01/2024	($292.00)
2667	A	Bonus Performance	11/01/2023	$608.65
2980	A	Miscellaneous Bilateral	02/01/2025	$293.49

Total Credits: **$9,674,978.83**

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

INVOICE NUMBER:	2025022810963	
CUSTOMER ACCOUNT:	Dominion Virginia Power (EDC)	
CUSTOMER IDENTIFIERS:	DOMEDC (10963)	
FINAL BILLING STATEMENT ISSUED:	03/07/2025 08:31:24	
BILLING PERIOD:	02/01/2025 to 02/28/2025	
Monthly Billing Total:		($136,091,830.04)
Previous Weekly Billing Total:		($125,812,463.65)

Monthly Billing Statement Summary	Total
Total Net Credit to You. Please Do Not Pay	$10,279,366.39

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 2025-03-14

Fed Wire/ACH Bank Instructions: [redacted]

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

Please be aware that PJM and PNC Bank would never send an email or make a phone call instructing a PJM Member to change bank instructions. PJM's bank instructions are only communicated on the PJM Billing Statements found in PJM's Market Settlement Reporting System (MSRS) or alternatively, in PJM's eCredit System. If needed, PJM bank instructions can be confirmed by calling PJM Member Relations at (866)400-8980.

This cover page includes PJM Settlement, Inc. banking information that is NOT to be publicly shared. In order to reduce the risk of potential fraud, please redact any PJM Settlement banking information prior to including these billing statements in any public documents.

Stephen Lawson
President

pjm Settlement

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power (EDC)

CUSTOMER IDENTIFIERS DOMEDC

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$0.00
1205		Balancing Spot Market Energy		($18.78)
1210		Day-ahead Transmission Congestion		$0.00
1215		Balancing Transmission Congestion		($0.57)
1220		Day-ahead Transmission Losses		$0.00
1225		Balancing Transmission Losses		($0.12)
1250		Meter Error Correction		$83,970.36
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		($0.10)
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		($0.02)
1305		PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$0.00
1313		PJM Settlement, Inc.		$292.18
1315		FERC Annual Recovery		($0.05)
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00

PJM Settlement, Inc.
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Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power (EDC)

CUSTOMER IDENTIFIERS DOMEDC

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

1340		Regulation and Frequency Response Service		($0.05)
1360		Synchronized Reserve		$0.00
1361		Secondary Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$0.22
1380		Black Start Service		$0.00
1400		Load Reconciliation for Spot Market Energy		($0.16)
1410		Load Reconciliation for Transmission Congestion		($0.33)
1420		Load Reconciliation for Transmission Losses		($0.02)
1250	A	Meter Error Correction	01/01/2025	$4,552.11
1375	A	Balancing Operating Reserve	04/01/2024	($0.01)
1375	A	Balancing Operating Reserve	05/01/2024	$0.01
1375	A	Balancing Operating Reserve	11/01/2024	$23.84
1375	A	Balancing Operating Reserve	01/01/2025	$0.01
1980	A	Miscellaneous Bilateral	02/01/2025	$135,756.76

Total Charges: **$224,575.28**

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power (EDC)

CUSTOMER IDENTIFIERS DOMEDC

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$134,561,473.25
2103		Underground Transmission Service		$928,852.33
2108		Transmission Enhancement		$263,950.88
2110		Direct Assignment Facilities		$231,202.58
2120		Other Supporting Facilities		$598,592.88
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2215		Balancing Transmission Congestion		$0.04
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Balancing Synchronized Reserve		$0.00
2361		Balancing Secondary Reserve		$0.00
2366		Day-ahead Synchronized Reserve		$0.00
2367		Day-ahead Secondary Reserve		$0.00
2368		Day-ahead Non-Synchronized Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Dominion Virginia Power (EDC)

CUSTOMER IDENTIFIERS DOMEDC

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
2415		Balancing Transmission Congestion Load Reconciliation		$0.04
2420		Load Reconciliation for Transmission Losses		($0.01)
2100	A	Network Integration Transmission Service	02/01/2025	($267,666.67)

Total Credits:	**$136,316,405.32**

No Data Found for billing period 2025-02-01 - 2025-02-28

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

INVOICE NUMBER:	2025022811082	
CUSTOMER ACCOUNT:	Virginia Electric & Power Company (DVP Sale)	
CUSTOMER IDENTIFIERS:	PEPDVP (11082)	
FINAL BILLING STATEMENT ISSUED:	03/07/2025 08:31:24	
BILLING PERIOD:	02/01/2025 to 02/28/2025	
Monthly Billing Total:		$58.87
Previous Weekly Billing Total:		$0.00

Monthly Billing Statement Summary	Total
Total Net Charge. Please Pay This Amount.	$58.87

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 2025-03-14

Fed Wire/ACH Bank Instructions: [redacted]

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

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Stephen Lawson
President

pjm Settlement

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Virginia Electric & Power Company (DVP Sale)

CUSTOMER IDENTIFIERS PEPDVP

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$0.00
1205		Balancing Spot Market Energy		$0.00
1210		Day-ahead Transmission Congestion		$0.00
1215		Balancing Transmission Congestion		$0.00
1220		Day-ahead Transmission Losses		$0.00
1225		Balancing Transmission Losses		$0.00
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$0.00
1305		PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$0.00
1313		PJM Settlement, Inc.		$58.44
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
1340		Regulation and Frequency Response Service		$0.00
1360		Synchronized Reserve		$0.00

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Virginia Electric & Power Company (DVP Sale)

CUSTOMER IDENTIFIERS PEPDVP

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

1361		Secondary Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$0.00
1380		Black Start Service		$0.00
1375	A	Balancing Operating Reserve	07/01/2023	$0.01
1375	A	Balancing Operating Reserve	10/01/2023	$0.04
1375	A	Balancing Operating Reserve	12/01/2023	$1.53
1375	A	Balancing Operating Reserve	03/01/2024	$0.03
1375	A	Balancing Operating Reserve	04/01/2024	($4.10)
1375	A	Balancing Operating Reserve	05/01/2024	$2.92

Total Charges: **$58.87**

PJM Settlement, Inc.
2750 Monroe Blvd.
Audubon, PA 19403

CUSTOMER ACCOUNT: Virginia Electric & Power Company (DVP Sale)

CUSTOMER IDENTIFIERS PEPDVP

FINAL BILLING STATEMENT ISSUED: 03/07/2025 08:31:24

BILLING PERIOD: 02/01/2025 to 02/28/2025

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Balancing Synchronized Reserve		$0.00
2361		Balancing Secondary Reserve		$0.00
2366		Day-ahead Synchronized Reserve		$0.00
2367		Day-ahead Secondary Reserve		$0.00
2368		Day-ahead Non-Synchronized Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00

Total Credits: **$0.00**

Derivation of NITS Charge, UG Transmission Charge, TEC Charge and Credit, and EL05-121 Settlement Charges to DOMLSE for February 2025

Table 1 - Network Integration Transmission Service Charge to DOMLSE

Line #	Description	Reference	PJM Invoice Billing Line Item*	Amount
1	Rate for Network Integration Transmission Service ($/MW/yr)	(a)		75,876.81
2	Daily Rate $/MW/day	L.1/(365 days/yr)		207.8816712
3	DOMLSE MW-days in February	(b)		511,692.50
4	NITS Charge ($/month)	L.2*L.3	1100	106,371,492

Table 1A - Underground Transmission Service Charge to DOMLSE

Line #	Description	Reference	PJM Invoice Billing Line Item*	Amount
1	Annual UG Transmission Rate ($/MW/yr)	(a)		541.18
2	Daily Rate $/MW/day	L.1/(365 days/yr)		1.4826849
3	DOMLSE Va MW-days in February	(b)		498,843.30
4	UG Transmission Charge ($/month)	L.2*L.3	1103	739,627

Table 2 - Transmission Enhancement Charge ("TEC") and EL05-121 Settlement Charges to DOMLSE

Line #	Description	Reference	PJM Invoice Billing Line Item*	Total $/month Col. A	Allocation Factor MW days Col. B	DOMLSE $/month Col. C = A*B
1	Transmission Enhancement	(c) and (e)	1108	$ 29,738,334	0.79050481	$ 23,508,296
2	Transmission Enhancement Charge Adjustment (EL05-121-009)	(d) and (e)	1115	$ 1,071,592	0.79050481	$ 847,098

Table 3 - Transmission Enhancement Credit to DOMLSE

Line #	Description	Reference	PJM Invoice Billing Line Item*	Total $/month Col. A	Allocation Factor MW days/year Col. B	DOMLSE $/month Col. C = A*B
1	Total TEC from Dominion Electric Transmission	(f)		$ 39,206,745		
2	Less Incentives	(g)		$ 263,951		
3	Dominion Transmission Enhancement Charges excluding Incentives Amount	L.1 less L.3, (e)	2108	$ 38,942,794	0.79050481	$ 30,784,466

Notes:

* Where applicable.

(a) The Rate for NITS is obtained from the Company's 1-15-25 Informational Filing of the 2025 Formula Rate Annual Update, Attachment A, Part 1, Formula Rate Appendix A, Page 4, Line 171 in FERC Docket No. ER09-545. The Annual UG Transmission Rate is obtained from the same Attachment A, Part 1 and is in Attachment 10, Line 7. See <https://www.pjm.com/-/media/DotCom/markets-ops/trans-service/jan-to-dec/2025/vepco/2025-formula-rate-annual-informational-filing.zip>.

(b) The DOMLSE MW Contribution to the Dominion Zone Network Service Peak Load ("NSPL") is the amount used by PJM for billing DOMLSE for NITS, and the DOMLSE MW Contribution to the Dominion Zone Virginia Network Service Peak Load ("Va NSPL") is the amount used by PJM for billing DOMLSE for Underground Transmission Service. See also note (e).

(c) The amount in Col. A, Line 1 is the total of the Monthly Revenue Requirements for all of the projects, and it is shown as the Total TEC under the Dominion column on Schedule 2, Page XX.

(d) The amount in Col. A, Line 2 is obtained from the PJM Open Access Transmission Tariff, Schedule 12-C Appendix C, in the column titled "Total TEC Adjustment Years 5 through 10." Schedule 12-C Appendix C is included in PJM's compliance filing to the Commission's 5/31/2018 Order in FERC Docket No. EL05-121 and was filed in FERC Docket No. ER18-2102 on 7/30/2018. See <https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20180730-5174>.

(e) The allocation factor is derived from the DOMLSE MW contribution to the Dominion Zone NSPL for 2025. See table below and <https://www.pjm.com/-/media/DotCom/markets-ops/settlements/network-service-peak-loads-2025.pdf>.

	MW Contribution to Dominion Zone NSPL Col. A	DOMLSE MW-days in February Col. C = 28*A	Virginia MW Contribution to Dominion Zone NSPL Col. B	DOMLSE Virginia MW-days in February Col. D = 28*B
DOMLSE February 1 - 28, 2025	18,274.73	511,692.50	17,815.83	498,843.30
Dominion Zone	23,117.80	647,298.40	22,373.80	626,466.40
Allocation Factor	0.790504812	0.790504812	0.796281014	0.796281014

(f) The amount in Col. A, Line 1 is the total monthly revenue requirement amount for the Dominion Projects on Schedule 2, Page X.

(g) The amount in Col. A, Line 2 is the Transmission Enhancement credit on Schedule 1, Page XX on line 2108 of the PJM February bill to DOMEDC.

Transmission Enhancement Charges (PJM OATT Schedule 12) Settlement Worksheet

Required Transmission Enhancements owned by: Trans-Allegheny Interstate Line Company (TrAILCo)

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (June 2024 - May 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion	
b0216	$ 2,801,985.00	$ 233,498.75	14.20%	$ 33,156.82
b0216_dfax	$ 2,801,985.00	$ 233,498.75	50.23%	$ 117,286.42
b0218	$ 2,759,374.37	$ 229,947.86	13.81%	$ 31,755.80
b0328.1 b0328.2 b0347.1 b0347.2 b0347.3 b0347.4	$ 67,330,114.55	$ 5,610,842.88	14.20%	$ 796,739.69
b0328.1_dfax	$ -	$ -	80.60%	$ -
b0328.2_dfax	$ 3,378,625.15	$ 281,552.10	80.60%	$ 226,930.99
b0347.1_dfax	$ 15,706,769.12	$ 1,308,897.43	44.37%	$ 580,757.79
b0347.2_dfax	$ 42,316,976.99	$ 3,526,414.75	63.32%	$ 2,232,925.82
b0347.3_dfax	$ 4,358,278.31	$ 363,189.86	44.37%	$ 161,147.34
b0347.4_dfax	$ 1,569,464.97	$ 130,788.75	63.32%	$ 82,815.44
b0323	$ 221,015.99	$ 18,418.00		$ -
b0230	$ 894,107.20	$ 74,508.93	11.75%	$ 8,754.80
b0559	$ 357,682.05	$ 29,806.84	14.20%	$ 4,232.57
b0559_dfax	$ 357,682.05	$ 29,806.84	63.32%	$ 18,873.69
b0229	$ 1,066,570.82	$ 88,880.90	14.50%	$ 12,887.73
b0495	$ 2,209,474.00	$ 184,122.83	14.20%	$ 26,145.44
b0495_dfax	$ 2,209,474.00	$ 184,122.83	81.30%	$ 149,691.86
b0343	$ 603,663.17	$ 50,305.26	28.86%	$ 14,518.10
b0344	$ 586,833.04	$ 48,902.75	28.82%	$ 14,093.77
b0345	$ 634,378.70	$ 52,864.89	28.83%	$ 15,240.95
b0704	$ 1,013,353.25	$ 84,446.10		$ -
b1243	$ 261,195.69	$ 21,766.31		$ -
b0563	$ 730,292.40	$ 60,857.70		$ -
b0564	$ 105,563.41	$ 8,796.95		$ -
b0674	$ 2,920,551.89	$ 243,379.32		$ -
b0674.1	$ -	$ -		$ -
b1023.3	$ 138,963.17	$ 11,580.26		$ -
b1770	$ 54,653.33	$ 4,554.44		$ -
b1990	$ 1,413,180.71	$ 117,765.06		$ -
b1965	$ 149,664.99	$ 12,472.08		$ -

b1839	$ 221,082.52	$ 18,423.54		$ -
b1998	$ 275,918.34	$ 22,993.19		$ -
b0556	$ 113,746.04	$ 9,478.84		$ -
b1153	$ 3,640,149.64	$ 303,345.80		$ -
b1023.1	$ 2,416,557.86	$ 201,379.82		$ -
b1941	$ 3,376,849.00	$ 281,404.08		$ -
b1803	$ 284,227.98	$ 23,685.67	14.20%	$ 3,363.37
b1803_dfax	$ 284,227.98	$ 23,685.67	67.11%	$ 15,895.45
b1800	$ 2,786,357.35	$ 232,196.45	14.20%	$ 32,971.90
b1800_dfax	$ 2,786,357.35	$ 232,196.45	39.46%	$ 91,624.72
b1804	$ 3,306,118.38	$ 275,509.86	14.20%	$ 39,122.40
b1804_dfax	$ 3,306,118.38	$ 275,509.86	63.32%	$ 174,452.84
b2433.1-b.2433.3	$ 7,746,557.78	$ 645,546.48		$ -
b1967	$ 509,711.30	$ 42,475.94		$ -
b1609 b1769	$ 1,221,849.02	$ 101,820.75		$ -
b1945	$ 943,139.76	$ 78,594.98		$ -
b1610	$ 285,847.91	$ 23,820.66		$ -
b1801	$ 4,611,815.81	$ 384,317.98	14.89%	$ 57,224.95
b1964	$ 1,026,549.41	$ 85,545.78		$ -
b2342	$ 237,078.91	$ 19,756.58		$ -
b1672	$ 70,913.29	$ 5,909.44		$ -
b2343	$ 118,908.90	$ 9,909.07		$ -
b1840	$ 2,108,811.12	$ 175,734.26		$ -
b2235	$ 5,089,120.31	$ 424,093.36		$ -
b2260	$ 83,423.32	$ 6,951.94		$ -
b1802	$ -	$ -	14.89%	$ -
b1608	$ 3,045,312.83	$ 253,776.07		$ -
b2944	$ 1,376,386.60	$ 114,698.88		$ -
b0555	$ 157,957.36	$ 13,163.11		$ -
b1943	$ 933,854.39	$ 77,821.20		$ -
b2364-b2364.1	$ 1,879,981.04	$ 156,665.09		$ -
b2362	$ 4,301,940.70	$ 358,495.06		$ -
b2156	$ 210,702.38	$ 17,558.53		$ -
b2546	$ 114,289.37	$ 9,524.11		$ -
b2545	$ 9,670,950.04	$ 805,912.50		$ -
b2441	$ 5,980,354.56	$ 498,362.88		$ -
b2547.1	$ 6,205,356.71	$ 517,113.06		

			$ -
b2475	$ 14,758,245.67	$ 1,229,853.81	$ -
b1991	$ 5,121,559.58	$ 426,796.63	$ -
b2261	$ 694,626.79	$ 57,885.57	$ -
b2494	$ 2,826,912.50	$ 235,576.04	$ -
s1041	$ -	$ -	$ -
b2587	$ 2,123,160.70	$ 176,930.06	$ -
b2118	$ -	$ -	$ -
b2996-b2996.2	$ 21,154,399.60	$ 1,762,866.63	$ -
TOTAL	$ 286,359,301.74	$ 23,863,275.10	$ 4,942,610.65

Required Transmission Enhancements owned by: Baltimore Gas and Electric Company's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (June 2024- May 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion	
b0298	$ 6,115,030.00	$ 509,585.83	11.54%	$ 58,806.20
b0244	$ 4,562,735.00	$ 380,227.92		$ -
b0477	$ 2,924,644.00	$ 243,720.33		$ -
b0497	$ 2,847,881.00	$ 237,323.42		$ -
b1016	$ 11,689,097.00	$ 974,091.42	16.10%	$ 156,828.72
b1251	$ 3,138,609.00	$ 261,550.75	18.76%	$ 49,066.92
b1251.1	$ 3,937,008.00	$ 328,084.00	18.76%	$ 61,548.56
b2766.1	$ 588,920.50	$ 49,076.71	14.20%	$ 6,968.89
b2766.1_dfax	$ 588,920.50	$ 49,076.71	39.76%	$ 19,512.90
b2992.3	$ 47,508.00	$ 3,959.00	27.05%	$ 1,070.91
b2992.4	$ 1,618,473.00	$ 134,872.75	27.05%	$ 36,483.08
b2992.1	$ 3,133,309.00	$ 261,109.08	27.05%	$ 70,630.01
b2992.2	$ 4,048,650.00	$ 337,387.50	27.05%	$ 91,263.32
TOTAL	$ 45,240,785.00	$ 3,770,065.42		$ 552,179.51

Required Transmission Enhancements owned by: Dominion Virginia Power's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Feb - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion	
b0217	$ 97,506.27	$ 8,125.52	14.20%	$ 1,153.82
b0217_dfax	$ 97,506.27	$ 8,125.52	67.11%	$ 5,453.04
b0222	$ 79,233.28	$ 6,602.77	14.20%	$ 937.59
b0222_dfax	$ 79,233.28	$ 6,602.77	80.60%	$ 5,321.83
b0226	$ 799,190.11	$ 66,599.18	85.73%	$ 57,095.48
b0403	$ 875,894.46	$ 72,991.21	83.94%	$ 61,268.82

b0328.1	$ 12,069,157.14	$ 1,005,763.09	14.20%	$ 142,818.36
b0328.1_dfax	$ 12,069,157.14	$ 1,005,763.09	80.60%	$ 810,645.05
b0328.3	$ 739,620.59	$ 61,635.05	14.20%	$ 8,752.18
b0328.3_dfax	$ 739,620.59	$ 61,635.05	63.32%	$ 39,027.31
b0328.4	$ 166,876.60	$ 13,906.38	14.20%	$ 1,974.71
b0328.4_dfax	$ 166,876.60	$ 13,906.38	80.60%	$ 11,208.54
b0768	$ 2,509,762.39	$ 209,146.87	100.00%	$ 209,146.87
b0337	$ 642,629.66	$ 53,552.47	100.00%	$ 53,552.47
b0311	$ 324,691.41	$ 27,057.62	100.00%	$ 27,057.62
b0231	$ 1,111,748.99	$ 92,645.75	14.20%	$ 13,155.70
b0231_dfax	$ 1,111,748.99	$ 92,645.75	100.00%	$ 92,645.75
b0456	$ 470,472.05	$ 39,206.00	40.08%	$ 15,713.76
b0227	$ 2,029,770.13	$ 169,147.51	67.38%	$ 113,971.59
b0455	$ 328,533.26	$ 27,377.77	50.82%	$ 13,913.38
b0453.1	$ 153,400.37	$ 12,783.36	92.75%	$ 11,856.57
b0453.2	$ 1,466,646.82	$ 122,220.57	92.75%	$ 113,359.58
b0453.3	$ 341,501.97	$ 28,458.50	92.75%	$ 26,395.26
b0837	$ 37,446.79	$ 3,120.57	14.20%	$ 443.12
b0837_dfax	$ 37,446.79	$ 3,120.57	100.00%	$ 3,120.57
b0327	$ 608,915.05	$ 50,742.92	76.18%	$ 38,655.96
b0329.2A	$ 4,352,697.91	$ 362,724.83	100.00%	$ 362,724.83
b0329.2B	$ 8,783,269.83	$ 731,939.15	14.20%	$ 103,935.36
b0329.2B_dfax	$ 8,783,269.83	$ 731,939.15	100.00%	$ 731,939.15
b0467.2	$ 556,257.76	$ 46,354.81		$ -
b1507	$ 17,614,308.14	$ 1,467,859.01	14.20%	$ 208,435.98
b1507_dfax	$ 17,614,308.14	$ 1,467,859.01	67.11%	$ 985,080.18
b0457	$ 5,531.58	$ 460.97	14.20%	$ 65.46
b0457_dfax	$ 5,531.58	$ 460.97	85.52%	$ 394.22
b0784	$ 3,835.65	$ 319.64	14.20%	$ 45.39
b0784_dfax	$ 3,835.65	$ 319.64	92.39%	$ 295.32
b1224	$ 1,536,775.95	$ 128,064.66	78.21%	$ 100,159.37
b1508.3	$ 126,709.71	$ 10,559.14	62.95%	$ 6,646.98
b1647	$ 848.45	$ 70.70	14.20%	$ 10.04
b1647_dfax	$ 848.45	$ 70.70	100.00%	$ 70.70
b1648	$ 848.45	$ 70.70	14.20%	$ 10.04
b1648_dfax	$ 848.45	$ 70.70	100.00%	$ 70.70
b1649	$ 44,766.77	$ 3,730.56	14.20%	

				$ 529.74
b1649_dfax	$ 44,766.77	$ 3,730.56	100.00%	$ 3,730.56
b1650	$ 44,766.77	$ 3,730.56	14.20%	$ 529.74
b1650_dfax	$ 44,766.77	$ 3,730.56	100.00%	$ 3,730.56
b1188.6	$ 1,817,192.34	$ 151,432.70	75.58%	$ 114,452.83
b1188	$ 79,093.08	$ 6,591.09	14.20%	$ 935.93
b1188_dfax	$ 79,093.08	$ 6,591.09	100.00%	$ 6,591.09
b1321	$ 4,213,919.73	$ 351,159.98	97.96%	$ 343,996.32
b0756.1	$ 220,452.23	$ 18,371.02	14.20%	$ 2,608.68
b0756.1_dfax	$ 220,452.23	$ 18,371.02	100.00%	$ 18,371.02
b1797	$ 979,761.13	$ 81,646.76	14.20%	$ 11,593.84
b1797_dfax	$ 979,761.13	$ 81,646.76	51.47%	$ 42,023.59
b1799	$ 1,421,226.45	$ 118,435.54	14.20%	$ 16,817.85
b1799_dfax	$ 1,421,226.45	$ 118,435.54	89.13%	$ 105,561.60
b1798	$ 6,016,977.45	$ 501,414.79	14.20%	$ 71,200.90
b1798_dfax	$ 6,016,977.45	$ 501,414.79	80.60%	$ 404,140.32
b1805	$ 2,004,806.68	$ 167,067.22	14.20%	$ 23,723.55
b1805_dfax	$ 2,004,806.68	$ 167,067.22	44.37%	$ 74,127.73
b1508.1	$ 7,110,052.19	$ 592,504.35	62.95%	$ 372,981.49
b1508.2	$ 1,302,367.94	$ 108,530.66	62.95%	$ 68,320.05
b2053	$ 4,781,574.50	$ 398,464.54		$ -
b1906.1	$ 557,901.47	$ 46,491.79	14.20%	$ 6,601.83
b1906.1_dfax	$ 557,901.47	$ 46,491.79	100.00%	$ 46,491.79
b1908	$ 7,080,042.74	$ 590,003.56	14.20%	$ 83,780.51
b1908_dfax	$ 7,080,042.74	$ 590,003.56	85.52%	$ 504,571.04
b1905.2	$ 101,955.64	$ 8,496.30	14.20%	$ 1,206.47
b1905.2_dfax	$ 101,955.64	$ 8,496.30	100.00%	$ 8,496.30
b1328	$ 434,306.15	$ 36,192.18	92.94%	$ 33,637.01
b1698	$ 2,574,863.47	$ 214,571.96	59.38%	$ 127,412.83
b1907	$ 2,093,803.10	$ 174,483.59	81.79%	$ 142,710.13
b1909	$ 380,924.79	$ 31,743.73	81.90%	$ 25,998.11
b1912	$ 11,220,894.99	$ 935,074.58	99.54%	$ 930,773.24
b1701	$ 363,428.22	$ 30,285.69	63.30%	$ 19,170.84
b1791	$ 287,742.86	$ 23,978.57	78.38%	$ 18,794.40
b1694	$ 2,639,627.90	$ 219,968.99	14.20%	$ 31,235.60
b1694_dfax	$ 2,639,627.90	$ 219,968.99	74.23%	$ 163,282.98
b1911	$ 2,483,728.76	$ 206,977.40	74.12%	$ 153,411.65

b2471_dfax	$ 440,937.75	$ 36,744.81	100.00%	$ 36,744.81
b2471	$ 440,937.75	$ 36,744.81	14.20%	$ 5,217.76
b1905.1	$ 15,026,848.02	$ 1,252,237.34	14.20%	$ 177,817.70
b1905.1_dfax	$ 15,026,848.02	$ 1,252,237.34	100.00%	$ 1,252,237.34
b1905.5	$ 600,833.64	$ 50,069.47	99.84%	$ 49,989.36
b1696	$ 23,105,242.73	$ 1,925,436.89	88.45%	$ 1,703,048.93
b2373	$ 2,503,691.42	$ 208,640.95	14.20%	$ 29,627.01
b2373_dfax	$ 2,503,691.42	$ 208,640.95	50.29%	$ 104,925.53
b1905.3	$ 13,379,729.76	$ 1,114,977.48	99.84%	$ 1,113,193.52
b1905.4	$ 9,912,143.99	$ 826,012.00	99.84%	$ 824,690.38
b2744_dfax	$ 3,318,564.13	$ 276,547.01	96.17%	$ 265,955.26
b2744	$ 3,318,564.13	$ 276,547.01	14.20%	$ 39,269.68
b1905.6	$ 164,602.46	$ 13,716.87	99.84%	$ 13,694.92
b1905.7	$ 12,878.99	$ 1,073.25	99.84%	$ 1,071.53
b1905.9	$ 10,289.77	$ 857.48	99.84%	$ 856.11
b2582	$ 5,445,076.13	$ 453,756.34	14.20%	$ 64,433.40
b2582_dfax	$ 5,445,076.13	$ 453,756.34	81.93%	$ 371,762.57
b2443	$ 5,940,892.54	$ 495,074.38	97.11%	$ 480,766.73
b2665	$ 4,640,396.79	$ 386,699.73	14.20%	$ 54,911.36
b2665_dfax	$ 4,640,396.79	$ 386,699.73	71.52%	$ 276,567.65
b2758	$ 3,423,567.00	$ 285,297.25	14.20%	$ 40,512.21
b2758_dfax	$ 3,423,567.00	$ 285,297.25	100.00%	$ 285,297.25
b2729	$ 1,112,227.95	$ 92,685.66	35.11%	$ 32,541.94
b2928	$ 1,911,374.69	$ 159,281.22	14.20%	$ 22,617.93
b2928_dfax	$ 1,911,374.69	$ 159,281.22	100.00%	$ 159,281.22
b2960.1	$ 1,081,702.54	$ 90,141.88	14.20%	$ 12,800.15
b2960.1_dfax	$ 1,081,702.54	$ 90,141.88	88.65%	$ 79,910.78
b2960.2	$ 1,130,781.70	$ 94,231.81	14.20%	$ 13,380.92
b2960.2_dfax	$ 1,130,781.70	$ 94,231.81	87.48%	$ 82,433.99
b2978	$ 6,600,387.14	$ 550,032.26	14.20%	$ 78,104.58
b2978_dfax	$ 6,600,387.14	$ 550,032.26	100.00%	$ 550,032.26
b2759	$ 39,732,389.27	$ 3,311,032.44	14.20%	$ 470,166.61
b2759_dfax	$ 39,732,389.27	$ 3,311,032.44	44.80%	$ 1,483,342.53
b3027.1	$ 3,101,081.36	$ 258,423.45	100.00%	$ 258,423.45
b3019	$ 5,940,752.83	$ 495,062.74	14.20%	$ 70,298.91
b3019_dfax	$ 5,940,752.83	$ 495,062.74	89.57%	$ 443,427.70
b3020	$ 2,268,560.45	$ 189,046.70	14.20%	

				$ 26,844.63
b3020_dfax	$ 2,268,560.45	$ 189,046.70	51.27%	$ 96,924.24
b3021	$ 3,838,281.32	$ 319,856.78	14.20%	$ 45,419.66
b3021_dfax	$ 3,838,281.32	$ 319,856.78	89.94%	$ 287,679.19
b3702	$ (270,118.75)	$ (22,509.90)	18.99%	$ (4,274.63)
b3718.3	$ 19,406,321.89	$ 1,617,193.49	14.20%	$ 229,641.48
b3718.3_dfax	$ 19,406,321.89	$ 1,617,193.49	89.54%	$ 1,448,035.05
TOTAL	$ 470,480,938.58	$ 39,206,744.84		$ 21,441,694.36
	$ 467,313,528.10	$ 38,942,793.97		
	$3,167,410.48	$263,950.87		

Required Transmission Enhancements owned by: PSE&G's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion	
b0130	$ 1,414,616.42	$ 117,884.70		$ -
b0134	$ 582,672.83	$ 48,556.07		$ -
b0145	$ 6,242,098.15	$ 520,174.85		$ -
b0411	$ 1,577,731.56	$ 131,477.63		$ -
b0498	$ 1,013,244.94	$ 84,437.08	14.20%	$ 11,990.07
b0498_dfax	$ 1,013,244.94	$ 84,437.08		$ -
b0161	$ 1,960,730.11	$ 163,394.18		$ -
b0169	$ 1,198,220.74	$ 99,851.73		$ -
b0170	$ 522,160.76	$ 43,513.40		$ -
b0489	$ 34,225,121.52	$ 2,852,093.46	14.20%	$ 404,997.27
b0489_dfax	$ 34,225,121.52	$ 2,852,093.46		$ -
b0489.4	$ 3,706,524.27	$ 308,877.02		$ -
b0172.2	$ 1,018.16	$ 84.85	14.20%	$ 12.05
b0172.2_dfax	$ 1,018.16	$ 84.85		$ -
b0813	$ 728,877.92	$ 60,739.83		$ -
b1017	$ 1,663,178.70	$ 138,598.23		$ -
b1018	$ 1,731,433.28	$ 144,286.11		$ -
b0489.5-9	$ 10,491.06	$ 874.25	14.20%	$ 124.14
b0489.5-9_dfax	$ 10,491.06	$ 874.25		$ -
b1410-1415	$ 675,112.31	$ 56,259.36	14.20%	$ 7,988.83
b1410-1415_dfax	$ 675,112.31	$ 56,259.36		$ -
b0290	$ 3,182,837.61	$ 265,236.47	14.20%	$ 37,663.58
b0290_dfax	$ 3,182,837.61	$ 265,236.47		$ -
b0472	$ 1,193,281.87	$ 99,440.16		$ -
b0664-0665	$ 1,542,050.76	$ 128,504.23		

				$ -
b0668	$ 532,762.01	$ 44,396.83		$ -
b0814	$ 3,860,924.26	$ 321,743.69		$ -
b1156	$ 30,735,725.16	$ 2,561,310.43		$ -
b1154	$ 31,495,645.95	$ 2,624,637.16		$ -
b1228	$ 1,845,210.19	$ 153,767.52		$ -
b1255	$ 4,133,250.90	$ 344,437.58		$ -
b1588	$ 1,077,866.39	$ 89,822.20		$ -
b2139	$ 1,752,169.03	$ 146,014.09		$ -
b1304.1-4	$ 56,729,035.79	$ 4,727,419.65		$ -
b1398	$ 39,103,073.74	$ 3,258,589.48		$ -
b1155	$ 5,402,256.22	$ 450,188.02		$ -
b1399	$ 6,362,600.68	$ 530,216.72		$ -
b2436.21_dfax	$ 3,110,676.69	$ 259,223.06		$ -
b2436.21	$ 3,110,676.69	$ 259,223.06	14.20%	$ 36,809.67
b2436.22_dfax	$ 2,299,961.94	$ 191,663.50		$ -
b2436.22	$ 2,299,961.94	$ 191,663.50	14.20%	$ 27,216.22
b2436.81_dfax	$ 2,595,298.22	$ 216,274.85		$ -
b2436.81	$ 2,595,298.22	$ 216,274.85	14.20%	$ 30,711.03
b2436.83_dfax	$ 2,595,298.22	$ 216,274.85		$ -
b2436.83	$ 2,595,298.22	$ 216,274.85	14.20%	$ 30,711.03
b2436.90_dfax	$ 1,439,563.86	$ 119,963.65		$ -
b2436.90	$ 1,439,563.86	$ 119,963.65	14.20%	$ 17,034.84
b2437.10	$ 2,557,009.25	$ 213,084.10		$ -
b2437.20	$ 834,008.87	$ 69,500.74		$ -
b2437.21	$ 833,983.15	$ 69,498.60		$ -
b2437.30	$ 3,216,690.95	$ 268,057.58		$ -
b1590	$ 996,031.01	$ 83,002.58		$ -
b1787	$ 2,891,430.86	$ 240,952.57		$ -
b2436.10_dfax	$ 8,242,072.99	$ 686,839.42		$ -
b2436.10	$ 8,242,072.99	$ 686,839.42	14.20%	$ 97,531.20
b2436.84_dfax	$ 2,517,762.98	$ 209,813.58		$ -
b2436.84	$ 2,517,762.98	$ 209,813.58	14.20%	$ 29,793.53
b2436.85_dfax	$ 2,517,762.94	$ 209,813.58		$ -
b2436.85	$ 2,517,762.94	$ 209,813.58	14.20%	$ 29,793.53
b0376	$ 50,324.63	$ 4,193.72	14.20%	$ 595.51
b0376_dfax	$ 50,324.63	$ 4,193.72		$ -

b1589	$ 2,114,197.44	$ 176,183.12		$ -
b2146	$ 15,122,915.68	$ 1,260,242.97		$ -
b2702_dfax	$ 1,070,346.40	$ 89,195.53		$ -
b2702	$ 1,070,346.40	$ 89,195.53	14.20%	$ 12,665.77
b2633.4	$ 2,737,138.36	$ 228,094.86	14.20%	$ 32,389.47
b2633.4_dfax	$ 2,737,138.36	$ 228,094.86		$ -
b2633.5	$ 7,299,631.10	$ 608,302.59		$ -
b2955	$ 9,846,477.07	$ 820,539.76		$ -
b2835.1	$ 8,251,974.65	$ 687,664.55		$ -
b2835.2	$ 5,288,125.82	$ 440,677.15		$ -
b2835.3	$ 876,782.89	$ 73,065.24		$ -
b2836.2	$ 7,868,343.19	$ 655,695.27		$ -
b2836.3	$ 5,113,661.47	$ 426,138.46		$ -
b2836.4	$ 9,833,890.80	$ 819,490.90		$ -
b2837.1	$ 3,777,221.31	$ 314,768.44		$ -
b2837.2	$ 1,343,534.27	$ 111,961.19		$ -
b2837.3	$ 1,000,392.72	$ 83,366.06		$ -
b2837.4	$ 3,693,359.16	$ 307,779.93		$ -
b2837.5	$ 3,903,348.57	$ 325,279.05		$ -
b2837.6	$ 3,812,879.12	$ 317,739.93		$ -
b2837.7	$ 1,351,541.88	$ 112,628.49		$ -
b2837.8	$ 1,000,392.72	$ 83,366.06		$ -
b2837.9	$ 332,711.43	$ 27,725.95		$ -
b2837.10	$ 3,360,677.46	$ 280,056.46		$ -
b2837.11	$ 3,910,087.34	$ 325,840.61		$ -
b0274	$ 1,620,835.49	$ 135,069.62		$ -
b2436.33	$ 15,135,048.30	$ 1,261,254.03		$ -
b2436.34	$ 12,125,202.57	$ 1,010,433.55		$ -
b2436.60	$ 4,095,486.77	$ 341,290.56		$ -
b2986.12	$ 6,114,169.01	$ 509,514.08		$ -
b2986.21	$ 5,911,952.60	$ 492,662.72		$ -
b2986.22	$ 11,819,703.07	$ 984,975.26		$ -
b2836.1	$ 6,695,229.07	$ 557,935.76		$ -
b2986.23	$ 2,512,752.07	$ 209,396.01		$ -
b2986.24	$ 1,064,006.27	$ 88,667.19		$ -
b2276	$ 2,917,428.81	$ 243,119.07		$ -
b2276.1	$ 18,307,131.11	$ 1,525,594.26		

			$ -
b2276.2	$ 3,450,488.46	$ 287,540.71	$ -
b2436.50	$ 6,270,256.73	$ 522,521.39	$ -
b2436.70	$ 7,803,806.96	$ 650,317.25	$ -
b2437.11	$ 2,557,009.25	$ 213,084.10	$ -
b2437.33	$ 2,458,563.01	$ 204,880.25	$ -
b2755	$ 5,487,665.11	$ 457,305.43	$ -
b2810.2	$ 5,507,146.81	$ 458,928.90	$ -
b2811	$ 2,711,778.38	$ 225,981.53	$ -
b2812	$ 4,018,102.48	$ 334,841.87	$ -
b2933.1	$ 8,483,995.85	$ 706,999.65	$ -
b2933.2	$ 7,661,761.13	$ 638,480.09	$ -
b2933.31	$ 3,639,932.19	$ 303,327.68	$ -
b2933.32	$ 12,614,586.69	$ 1,051,215.56	$ -
b2934	$ 3,793,341.56	$ 316,111.80	$ -
b2935	$ 4,862,373.13	$ 405,197.76	$ -
b2935.1	$ 4,788,780.45	$ 399,065.04	$ -
b2935.2	$ 4,199,032.70	$ 349,919.39	$ -
b2935.3	$ 5,120,806.74	$ 426,733.90	$ -
b2956	$ 15,254,282.94	$ 1,271,190.25	$ -
b2982.1	$ 10,219,511.62	$ 851,625.97	$ -
b2982.2	$ 6,874,004.85	$ 572,833.74	$ -
b2983	$ 4,623,880.09	$ 385,323.34	$ -
b2983.1	$ 4,623,645.50	$ 385,303.79	$ -
b2983.2	$ 4,623,403.81	$ 385,283.65	$ -
b2986.11	$ 68,926,732.52	$ 5,743,894.38	$ -
b3003.1	$ 754,021.32	$ 62,835.11	$ -
b3003.2	$ 641,309.51	$ 53,442.46	$ -
b3003.3	$ 7,088,031.16	$ 590,669.26	$ -
b3003.4	$ 4,704,874.07	$ 392,072.84	$ -
b3003.5	$ 241,329.15	$ 20,110.76	$ -
b3004	$ 3,254,311.87	$ 271,192.66	$ -
b3004.1	$ 3,252,420.35	$ 271,035.03	$ -
b3004.2	$ 3,254,311.87	$ 271,192.66	$ -
b3004.3	$ 3,254,311.87	$ 271,192.66	$ -
b3004.4	$ 66,109.18	$ 5,509.10	$ -
b3025.1	$ 7,977,030.24	$ 664,752.52	$ -

b3025.2	$ 9,049,154.10	$ 754,096.18	$ -
b3025.3	$ 6,448,312.42	$ 537,359.37	$ -
b3705	$ 758,679.56	$ 63,223.30	$ -
TOTAL	$ 803,731,504.21	$ 66,977,625.44	$ 808,027.72

Required Transmission Enhancements owned by: PPL Electric Utilities Corp. dba PPL Utilities

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges Dominion
b0487	$ 30,920,357.00	$ 2,576,696.42	14.20% $ 365,890.89
b0487_dfax	$ 30,920,357.00	$ 2,576,696.42	$ -
b0171.2	$ 3,420.50	$ 285.04	14.20% $ 40.48
b0171.2_dfax	$ 3,420.50	$ 285.04	$ -
b0172.1	$ 2,453.00	$ 204.42	14.20% $ 29.03
b0172.1_dfax	$ 2,453.00	$ 204.42	$ -
b0284.2	$ 4,976.50	$ 414.71	14.20% $ 58.89
b0284.2_dfax	$ 4,976.50	$ 414.71	$ -
b0487.1	$ 1,470,482.00	$ 122,540.17	$ -
b0791	$ 324,108.00	$ 27,009.00	$ -
b0468	$ 2,000,393.00	$ 166,699.42	$ -
b2006	$ 946,903.00	$ 78,908.58	$ -
b2006.1	$ 2,006,358.50	$ 167,196.54	14.20% $ 23,741.91
b2006.1_dfax	$ 2,006,358.50	$ 167,196.54	$ -
b2237	$ 725,830.50	$ 60,485.88	14.20% $ 8,588.99
b2237_dfax	$ 725,830.50	$ 60,485.88	$ -
b2716	$ 681,163.00	$ 56,763.58	14.20% $ 8,060.43
b2716_dfax	$ 681,163.00	$ 56,763.58	$ -
b2824	$ 830,328.50	$ 69,194.04	14.20% $ 9,825.55
b2824_dfax	$ 830,328.50	$ 69,194.04	$ -
b2552.2	$ 65,668.00	$ 5,472.33	$ -
b3698	$ 2,166,594.00	$ 180,549.50	3.25% $ 5,867.86
TOTAL	$ 77,323,923.00	$ 6,443,660.26	$ 422,104.03

Required Transmission Enhancements owned by: AEP East Operating Companies and AEP Transmission Companies

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges Dominion
b0504	$ 299,032.50	$ 24,919.38	14.20% $ 3,538.55
b0504_dfax	$ 299,032.50	$ 24,919.38	

				$ -
b0318	$ 1,200,012.00	$ 100,001.00		$ -
b0839	$ 731,865.00	$ 60,988.75		$ -
b1231	$ 1,164,771.00	$ 97,064.25		$ -
b0570	$ 1,346,644.00	$ 112,220.33		$ -
b1465.2	$ 765,760.50	$ 63,813.38	14.20%	$ 9,061.50
b1465.2_dfax	$ 765,760.50	$ 63,813.38		$ -
b1465.4	$ 318,780.00	$ 26,565.00	14.20%	$ 3,772.23
b1465.4_dfax	$ 318,780.00	$ 26,565.00		$ -
b1034.1	$ 1,688,930.00	$ 140,744.17		$ -
b1034.6	$ 256,235.00	$ 21,352.92		$ -
b1465.3	$ 1,089,502.00	$ 90,791.83	14.20%	$ 12,892.44
b1465.3_dfax	$ 1,089,502.00	$ 90,791.83		$ -
b1712.2	$ 233,343.00	$ 19,445.25	75.30%	$ 14,642.27
b1864.2	$ 235,064.00	$ 19,588.67		$ -
b2048	$ 651,843.00	$ 54,320.25		$ -
b1034.8	$ 512,387.00	$ 42,698.92		$ -
b1870	$ 816,307.00	$ 68,025.58		$ -
b1032.2	$ 2,821,368.00	$ 235,114.00		$ -
b1034.2	$ 1,223,321.00	$ 101,943.42		$ -
b1034.3	$ 1,656,966.00	$ 138,080.50		$ -
b2020	$ 18,239,564.00	$ 1,519,963.67		$ -
b2021	$ 5,275,639.00	$ 439,636.58		$ -
b1659.14	$ 3,407,294.50	$ 283,941.21	14.20%	$ 40,319.65
b1659.14_dfax	$ 3,407,294.50	$ 283,941.21	27.57%	$ 78,282.59
b2032	$ 475,343.00	$ 39,611.92		$ -
b1034.7	$ 545,241.00	$ 45,436.75		$ -
b2018	$ 2,541,862.00	$ 211,821.83		$ -
b1864.1	$ 9,132,025.00	$ 761,002.08		$ -
b1661	$ 109,044.00	$ 9,087.00	14.20%	$ 1,290.35
b1661_dfax	$ 109,044.00	$ 9,087.00		$ -
b2017	$ 8,984,709.00	$ 748,725.75	6.19%	$ 46,346.12
b1818	$ 8,051,041.00	$ 670,920.08		$ -
b1819	$ 10,833,331.00	$ 902,777.58		$ -
b1032.4	$ 930,913.00	$ 77,576.08		$ -
b1666	$ 2,699,841.00	$ 224,986.75		$ -
b1957	$ 1,213,386.00	$ 101,115.50		$ -

b1962	$ 1,153,644.50	$ 96,137.04	14.20%	$ 13,651.46
b1962_dfax	$ 1,153,644.50	$ 96,137.04		$ -
b2019	$ 7,248,989.00	$ 604,082.42		$ -
b1032.1	$ 3,521,113.00	$ 293,426.08		$ -
b1948	$ 5,728,736.00	$ 477,394.67	13.97%	$ 66,692.04
b2022	$ 444,239.00	$ 37,019.92		$ -
b1660	$ 178,934.00	$ 14,911.17	14.20%	$ 2,117.39
b1660_dfax	$ 178,934.00	$ 14,911.17		$ -
b1660.1	$ 1,569,155.00	$ 130,762.92	14.20%	$ 18,568.33
b1660.1_dfax	$ 1,569,155.00	$ 130,762.92		$ -
b1663.2	$ 280,962.50	$ 23,413.54	14.20%	$ 3,324.72
b1663.2_dfax	$ 280,962.50	$ 23,413.54		$ -
b1875	$ 9,113,290.00	$ 759,440.83		$ -
b1797.1	$ 3,168,300.50	$ 264,025.04	14.20%	$ 37,491.56
b1797.1_dfax	$ 3,168,300.50	$ 264,025.04	51.47%	$ 135,893.69
b1659	$ 5,593,231.00	$ 466,102.58		$ -
b1659.13	$ 2,685,486.50	$ 223,790.54	14.20%	$ 31,778.26
b1659.13_dfax	$ 2,685,486.50	$ 223,790.54		$ -
b1495	$ 4,466,460.00	$ 372,205.00		$ -
b1712.1	$ 26,402.00	$ 2,200.17	75.30%	$ 1,656.73
b1465.1	$ 3,534,198.00	$ 294,516.50	3.89%	$ 11,456.69
b2230	$ 688,010.50	$ 57,334.21	14.20%	$ 8,141.46
b2230_dfax	$ 688,010.50	$ 57,334.21		$ -
b2423	$ 1,067,362.00	$ 88,946.83	14.20%	$ 12,630.45
b2423_dfax	$ 1,067,362.00	$ 88,946.83		$ -
b2687.1_dfax	$ 3,868,871.00	$ 322,405.92		$ -
b2687.1	$ 3,868,871.00	$ 322,405.92	14.20%	$ 45,781.64
b2687.2_dfax	$ 510,658.50	$ 42,554.88		$ -
b2687.2	$ 510,658.50	$ 42,554.88	14.20%	$ 6,042.79
b1465.5	$ 479,382.00	$ 39,948.50	14.20%	$ 5,672.69
b1465.5_dfax	$ 479,382.00	$ 39,948.50		$ -
b2831.1	$ 74,514.00	$ 6,209.50		$ -
b2833	$ 2,978,589.00	$ 248,215.75		$ -
b2777	$ 5,073,739.00	$ 422,811.58		$ -
b2668	$ 357,988.00	$ 29,832.33		$ -
b2776	$ 1,138,757.00	$ 94,896.42		$ -
b3775.10_rel	$ -	$ -		

			$ -
b3775.10_mkt	$ -	$ -	20.09% $ -
b3775.6_rel	$ -	$ -	$ -
b3775.6_mkt	$ -	$ -	20.09% $ -
b3775.7_rel	$ -	$ -	$ -
b3775.7_mkt	$ -	$ -	20.09% $ -
b1034.4	$ 837,626.00	$ 69,802.17	$ -
b1034.5	$ -	$ -	$ -
b3800.121	$ 3,481.00	$ 290.08	14.20% $ 41.19
b3800.121_dfax	$ 3,481.00	$ 290.08	62.25% $ 180.57
TOTAL	$ 176,887,145.00	$ 14,740,595.44	$ 611,267.37

Required Transmission Enhancements owned by: Atlantic Electric's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (June 2024 - May 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion
b0265	$ 433,385.00	$ 36,115.42	$ -
b0276	$ 665,663.00	$ 55,471.92	$ -
b0211	$ 1,129,944.00	$ 94,162.00	$ -
b0210.A	$ 1,125,455.50	$ 93,787.96	14.20% $ 13,317.89
b0210.A_dfax	$ 1,125,455.50	$ 93,787.96	$ -
b0210.B	$ 1,604,983.00	$ 133,748.58	$ -
b1398.5	$ 418,527.00	$ 34,877.25	$ -
b1398.3.1	$ 1,299,242.00	$ 108,270.17	$ -
b1600	$ 1,553,791.00	$ 129,482.58	$ -
b0210.1	$ 1,378,064.00	$ 114,838.67	$ -
b0212	$ 5,865.00	$ 488.75	$ -
TOTAL	$ 10,740,375.00	$ 895,031.26	$ 13,317.89

Required Transmission Enhancements owned by: Delmarva's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (June 2024 - May 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion
b0241.3	$ 1,415,373.00	$ 117,947.75	$ -
b0272.1	$ 10,996.50	$ 916.38	14.20% $ 130.13
b0272.1_dfax	$ 10,996.50	$ 916.38	$ -
b0751	$ 255,381.00	$ 21,281.75	14.20% $ 3,022.01
b0751_dfax	$ 255,381.00	$ 21,281.75	$ -
b0733	$ 1,095,271.00	$ 91,272.58	$ -
b1247	$ 738,881.00	$ 61,573.42	

			$ -
b2633.10	$ 693,268.00	$ 57,772.33	
			$ -
TOTAL	$ 4,475,548.00	$ 372,962.34	$ 3,152.13

Required Transmission Enhancements owned by: PEPCO's Network Customers			Responsible Customers'/Zones' allocation shares of monthly charges
PJM Upgrade ID	**Annual Revenue Requirement**	**Monthly Revenue Requirement (June 2024- May 2025)**	**Dominion**
b0367.1-2	$ 2,111,198.00	$ 175,933.17	$ -
b0512.7	$ 99,687.00	$ 8,307.25	14.20% $ 1,179.63
b0512.7_dfax	$ 99,687.00	$ 8,307.25	0.30% $ 24.92
b0512.8	$ -	$ -	14.20% $ -
b0512.8_dfax	$ -	$ -	0.30% $ -
b0512.9	$ 99,687.00	$ 8,307.25	14.20% $ 1,179.63
b0512.9_dfax	$ 99,687.00	$ 8,307.25	0.30% $ 24.92
b0512.12	$ 100,889.00	$ 8,407.42	14.20% $ 1,193.85
b0512.12_dfax	$ 100,889.00	$ 8,407.42	0.30% $ 25.22
b0478	$ 1,726,972.00	$ 143,914.33	$ -
b0499	$ 3,213,924.00	$ 267,827.00	$ -
b0526	$ 6,015,763.00	$ 501,313.58	$ -
b0701.1	$ 536,762.00	$ 44,730.17	$ -
b0496	$ 2,143,380.00	$ 178,615.00	10.91% $ 19,486.90
b0288	$ 3,266,607.00	$ 272,217.25	17.00% $ 46,276.93
b1125	$ 5,756,565.00	$ 479,713.75	$ -
b2008	$ 969,802.00	$ 80,816.83	$ -
b0467.1	$ 891,778.00	$ 74,314.83	$ -
b1126	$ 4,286,110.00	$ 357,175.83	$ -
b1596	$ 1,044,245.00	$ 87,020.42	$ -
TOTAL	$ 32,563,632.00	$ 2,713,636.00	$ 69,392.01

Required Transmission Enhancements owned by: Duquesne Light Company's Network Customers			Responsible Customers'/Zones' allocation shares of monthly charges
PJM Upgrade ID	**Annual Revenue Requirement**	**Monthly Revenue Requirement (June 2024- May 2025)**	**Dominion**
b0501-b0503	$ 23,567,520.00	$ 1,963,960.00	$ -
b1022.2	$ 433,380.00	$ 36,115.00	$ -
b3015.2	$ 832,672.00	$ 69,389.33	$ -
b3012.2	$ -	$ -	$ -
b1969	$ 1,520,172.00	$ 126,681.00	$ -
b2689.1-2	$ 1,044,196.00	$ 87,016.33	8.81% $ 7,666.14

TOTAL	$ 27,397,940.00	$ 2,283,161.66	$ 7,666.14

Required Transmission Enhancements owned by: Commonwealth Edison Company's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (June 2024 - May 2025)	Responsible Customers'/Zones' allocation shares of monthly charges Dominion
b2141	$ 26,170,965.00	$ 2,180,913.75	0.16% $ 3,489.46
b2728	$ 1,231,750.00	$ 102,645.83	$ -
b2692.1-b2692.2	$ 1,259,404.00	$ 104,950.33	5.15% $ 5,404.94
TOTAL	$ 28,662,119.00	$ 2,388,509.91	$ 8,894.40

Required Transmission Enhancements owned by: Jersey Central Power & Light (Transmission)

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges Dominion
b0174	$ 1,417,447.30	$ 118,120.61	$ -
b0268	$ 698,796.93	$ 58,233.08	$ -
b0726	$ 883,088.05	$ 73,590.67	$ -
b2015	$ 21,128,269.80	$ 1,760,689.15	$ -
TOTAL	$ 24,127,602.08	$ 2,010,633.51	$ -

Required Transmission Enhancements owned by: Mid-Atlantic Interstate Transmission, LLC

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges Dominion
b0215	$ 2,205,097.00	$ 183,758.08	$ -
b0549	$ 292,180.54	$ 24,348.38	14.20% $ 3,457.47
b0549_dfax	$ 292,180.54	$ 24,348.38	$ -
b0551	$ 238,086.32	$ 19,840.53	$ -
b0552	$ 191,104.14	$ 15,925.35	$ -
b0553	$ 168,814.03	$ 14,067.84	$ -
b0557	$ 397,240.67	$ 33,103.39	$ -
b1993	$ 2,025,164.09	$ 168,763.67	$ -
b1994	$ 11,969,633.41	$ 997,469.45	$ -
b2006.1.1	$ 319,214.39	$ 26,601.20	14.20% $ 3,777.37
b2006.1.1_dfax	$ (144,816.12)	$ (12,068.01)	$ -
b2452	$ 1,398,386.32	$ 116,532.19	36.92% $ 43,023.68
b2452.1	$ 327,091.39	$ 27,257.62	36.92% $ 10,063.51
b2743.2	$ (166,595.91)	$ (13,882.99)	39.95% $ (5,546.25)
b2743.3	$ (57,113.95)	$ (4,759.50)	39.95% $ (1,901.42)
b2743.4	$ 4,213.79	$ 351.15	39.95% $ 140.28
b0132.3	$ 26,432.69	$ 2,202.72	

				$ -
b1364	$ 21,693.18	$ 1,807.76		$ -
b1362	$ 11,855.90	$ 987.99		$ -
b1816.4	$ 11,315.75	$ 942.98		$ -
b2688.1	$ 2,519,692.16	$ 209,974.35	44.85%	$ 94,173.50
b0284.3	$ 2,485.68	$ 207.14	14.20%	$ 29.41
b0284.3_dfax	$ 2,485.68	$ 207.14		$ -
b0369	$ 121,798.52	$ 10,149.88	14.20%	$ 1,441.28
b0369_dfax	$ 121,798.52	$ 10,149.88		$ -
b2552.1	$ 18,443,736.05	$ 1,536,978.00		$ -
b3311	$ -	$ -		$ -
b2006.2.1	$ (10,113,901.41)	$ (842,825.12)		$ -
b3145	$ 1,175,677.11	$ 97,973.09	52.77%	$ 51,700.40
b2752.4	$ (4,189.09)	$ (349.09)	39.95%	$ (139.46)
TOTAL	$ 31,800,761.40	$ 2,650,063.45		$ 200,219.78

Required Transmission Enhancements owned by: PECO Energy Company

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (June 2024 - May 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion	
b0269	$ 2,003,296.50	$ 166,941.38	14.20%	$ 23,705.68
b0269_dfax	$ 2,003,296.50	$ 166,941.38		$ -
b0269.10	$ 2,621,807.00	$ 218,483.92		$ -
b1591	$ 774,153.00	$ 64,512.75		$ -
b0269.6	$ 208,372.50	$ 17,364.38	14.20%	$ 2,465.74
b0269.6_dfax	$ 208,372.50	$ 17,364.38		$ -
b0171.1	$ 281,136.00	$ 23,428.00	14.20%	$ 3,326.78
b0171.1_dfax	$ 281,136.00	$ 23,428.00		$ -
b1590.1-b1590.2	$ 1,747,415.00	$ 145,617.92		$ -
b1900	$ 3,855,467.00	$ 321,288.92		$ -
b0727	$ 2,458,635.00	$ 204,886.25		$ -
b2140	$ 2,331,341.00	$ 194,278.42		$ -
b1182	$ 2,320,649.00	$ 193,387.42		$ -
b1717	$ 1,551,237.00	$ 129,269.75		$ -
b1178	$ 1,096,870.00	$ 91,405.83		$ -
b0790	$ 233,490.00	$ 19,457.50		$ -
b0506	$ 276,854.00	$ 23,071.17		$ -
b0505	$ 309,336.00	$ 25,778.00		$ -
b0789	$ 319,570.00	$ 26,630.83		$ -

b0206	$ 434,232.00	$ 36,186.00		$ -
b0207	$ 585,225.00	$ 48,768.75		$ -
b0209	$ 331,614.00	$ 27,634.50		$ -
b0264	$ 263,340.00	$ 21,945.00		$ -
b0357	$ 263,221.00	$ 21,935.08		$ -
b1398.8	$ 195,617.00	$ 16,301.42		$ -
b0287	$ 321,722.50	$ 26,810.21	14.20%	$ 3,807.05
b0287_dfax	$ 321,722.50	$ 26,810.21		$ -
b0208	$ 480,123.00	$ 40,010.25		$ -
b2694	$ 1,873,570.00	$ 156,130.83	0.35%	$ 546.46
b2766.2	$ 78,965.00	$ 6,580.42	14.20%	$ 934.42
b2766.2_dfax	$ 78,965.00	$ 6,580.42		$ -
TOTAL	$ 30,110,751.00	$ 2,509,229.29		$ 34,786.12

Required Transmission Enhancements owned by: American Transmission Systems, Inc.

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges	
			Dominion	
b1587	$ 1,761,178.01	$ 146,764.83		$ -
b1920	$ 2,784,510.41	$ 232,042.53		$ -
b1977	$ 5,476,218.57	$ 456,351.55		$ -
b1959	$ 13,470,147.29	$ 1,122,512.27		$ -
b2972	$ 591,058.95	$ 49,254.91	5.31%	$ 2,615.44
b2124.4	$ 3,178,595.29	$ 264,882.94		$ -
b2124.1	$ 992,264.15	$ 82,688.68		$ -
b2124.2	$ 2,213,227.45	$ 184,435.62		$ -
b2435	$ 18,744,017.24	$ 1,562,001.44		$ -
TOTAL	$ 49,211,217.36	$ 4,100,934.77		$ 2,615.44

Required Transmission Enhancements owned by: Transource West Virginia, LLC

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges	
			Dominion	
b2609.4	$ 9,346,941.35	$ 778,911.78		$ -
TOTAL	$ 9,346,941.35	$ 778,911.78		$ -

Required Transmission Enhancements owned by: Transource Maryland, LLC

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges	
			Dominion	
b2743.5 b2752.5	$ 1,972,893.32	$ 164,407.78	39.95%	$ 65,680.91

TOTAL	$ 1,972,893.32	$ 164,407.78	$ 65,680.91

Required Transmission Enhancements owned by: Transource Pennsylvania, LLC

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion
b2743.5 b2743.1. b2752.5 b2752.1	$ 12,339,041.84	$ 1,028,253.49	39.95% $ 410,787.27
b3737.47	$ 364,041.43	$ 30,336.79	14.20% $ 4,307.82
b3737.47_dfax	$ 364,041.43	$ 30,336.79	$ -
b3737.47_pub	$ 1,995,758.76	$ 166,313.23	$ -
TOTAL	$ 15,062,883.47	$ 1,255,240.30	$ 415,095.09

Required Transmission Enhancements owned by: Silver Run Electric, Inc.

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion
b2633.1-b2633.2	$ 22,578,434.41	$ 1,881,536.20	$ -
TOTAL	$ 22,578,434.41	$ 1,881,536.20	$ -

Required Transmission Enhancements owned by: Northern Indiana Public Service Company (NIPSCO) in Midcontinent Independent System Operator, Inc. (MISO)

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion
b2971	$ 799,509.00	$ 66,625.75	15.20% $ 10,127.11
b2973	$ 758,112.00	$ 63,176.00	14.70% $ 9,286.87
b2974	$ 6,163.00	$ 513.58	$ -
b2975	$ 889,793.00	$ 74,149.42	4.35% $ 3,225.50
b3142	$ 3,977,618.00	$ 331,468.17	$ -
TOTAL	$ 6,431,195.00	$ 535,932.92	$ 22,639.49

Required Transmission Enhancements owned by: Transmission Owners in Midcontinent Independent System Operator, Inc. (MISO)

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (June 2024 - May 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion
b3053	$ 881,798.00	$ 73,483.17	$ -
TOTAL	$ 881,798.00	$ 73,483.17	$ -

Required Transmission Enhancements owned by: The Dayton Power & Light Company

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion
b1570	$ 2,706,239.00	$ 225,519.92	$ -
TOTAL	$ 2,706,239.00	$ 225,519.92	$ -

Required Transmission Enhancements owned by: South FirstEnergy Operating Companies

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion	
b0577	$ -	$ -	14.20%	$ -
b0577_dfax	$ -	$ -		$ -
b2609.5	$ 380,334.69	$ 31,694.56		$ -
b0238	$ 497,094.98	$ 41,424.58	33.66%	$ 13,943.51
b0373	$ 359,947.81	$ 29,995.65		$ -
b1507.2	$ 10,164.08	$ 847.01	14.20%	$ 120.28
b1507.2_dfax	$ 10,164.08	$ 847.01	67.11%	$ 568.43
b1507.3	$ 1,302,518.58	$ 108,543.21	14.20%	$ 15,413.14
b1507.3_dfax	$ 1,302,518.58	$ 108,543.21	67.11%	$ 72,843.35
b2688.3	$ 86,221.01	$ 7,185.08	44.85%	$ 3,222.51
b0347.17-32	$ 167,533.11	$ 13,961.09	14.20%	$ 1,982.47
b0347.17-32_dfax	$ 167,533.11	$ 13,961.09	63.32%	$ 8,840.16
b1835	$ 1,972.30	$ 164.36	34.46%	$ 56.64
TOTAL	$ 4,286,002.35	$ 357,166.85		$ 116,990.49

Required Transmission Enhancements owned by: Keystone Appalachian Transmission Company

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2025)	Responsible Customers'/Zones' allocation shares of monthly charges: Dominion
b1022.11*	$ 69,792.75	$ 5,816.06	$ -
b1022.5*	$ 87,742.23	$ 7,311.85	$ -
b3006*	$ 17,589,173.09	$ 1,465,764.42	$ -
b3011.2*	$ 136,904.00	$ 11,408.67	$ -
b3011.5*	$ 180,421.52	$ 15,035.13	$ -
b2965*	$ 444,958.99	$ 37,079.92	$ -
b3214	$ 4,144,213.62	$ 345,351.14	$ -
b3717.1	$ 561,415.58	$ 46,784.63	$ -
TOTAL	$ 23,214,621.77	$ 1,934,551.82	$ -

*Project previously owned by South FirstEnergy Operating Companies

Total TEC to the Dominion Zone $ 29,738,333.52

numbers in black	No change for project from previous posting
numbers in red	Value changed for project from previous posting
highlighted rows	New project

ATTACHMENT H-16B

FORMULA RATE IMPLEMENTATION PROTOCOLS

Section 1 Annual Updates

a. No later than September 15 of each year, VEPCO shall cause to be posted on the www.PJM.com website the following information (the "Annual Update"):

(i) VEPCO's Annual Transmission Revenue Requirement ("ATRR"), rate for Network Integration Transmission Service ("NITS"), based on applying its projected costs, revenues and credits, other than those credits that will be distributed to customers pursuant to section 2 of Attachment H-16, for the next calendar year, plus its True-up Adjustment calculated pursuant to the Formula Rate set out in Attachment H-16A,

(ii) an estimate of the Network Service Peak Load of the Dominion Zone that will be used by the Transmission Provider to determine each Network Customer's Zone Network Load pursuant to Section 34.1 and Attachment H-16 for the next calendar year; and

(iii) an explanation of any change in VEPCO's accounting policies and practices that took effect in the preceding twelve months ending August 31 that is reported in Notes 3 and 4 of VEPCO's Securities and Exchange Commission Form 10-Q ("Material Accounting Changes"). To the extent there are Material Accounting Changes, VEPCO's Form 10-Q will be posted on PJM's website at the time of the Annual Update.

b. Upon written request, VEPCO will make available to any entity that is or may become a customer taking transmission service on the VEPCO facilities operated by the Transmission Provider, any state regulatory commission with jurisdiction over the VEPCO facilities located in the area served by the Transmission Provider, and any party having standing under Section 206 of the Federal Power Act (an "Interested Party") a "workable" Excel file containing that year's Annual Update data.

c. No later than September 30 of each year, VEPCO shall hold a public meeting to explain the Annual Update for the next calendar year. VEPCO shall modify the Annual Update to reflect any changes that it and the Interested Parties agree upon by no later than December 18, and shall cause the revised Annual Update to be posted on the www.PJM.com website no later than January 15. VEPCO shall cause the Annual Update, as revised pursuant to the procedures set out above, to be included in an informational filing with the Commission by no later than January 15. This filing will not require Commission action.

d. The ATRR and the Rate for Network Integration Transmission Service, determined pursuant to Section 1.a above and adjusted pursuant to Sections 2 and 3, below, shall be effective for the next calendar year.

e. If after September 15, PJM determines the actual Network Service Peak Load for the Dominion Zone that will be used by the Transmission Provider to determine each Network Customer's Zone Network Load pursuant to Section 34.1 and

Attachment H-16 for the next calendar year differs from the value posted pursuant to Section 1.a.ii., above, the Rate for Network Integration Transmission Service shall be adjusted to reflect the updated Network Service Peak Load and VEPCO shall cause an updated calculation of the Rate for Network Integration Transmission Service to be posted on the www.PJM.com website no later than fifteen (15) business days following the posting by PJM of the actual Network Service Peak Load for the Dominion Zone.

Section 2 Annual Review Procedures

a. No later than June 15 of each year, VEPCO shall cause to be posted on the www.PJM.com website the following information:

(i) the adjusted ATRR for the previous calendar year, calculated by applying the methodology set out in Attachment H-16A Appendix A to VEPCO's actual costs for that calendar year; and

(ii) the True-Up Adjustment Before Interest for the previous calendar year, calculated pursuant to Attachment H-16A, Attachment 6.

b. No later than October 25 of each year, any Interested Party may serve information requests on VEPCO concerning the adjusted ATRR for the previous calendar year and the True-Up Adjustment ("Information Requests"). Information Requests shall be limited to what is necessary to determine whether VEPCO has properly calculated the True-Up Adjustment and its components and the procedures in this Attachment H-16B. Information Requests shall not (i) otherwise be directed to ascertaining whether the Formula Rate is just and reasonable; (ii) solicit information concerning costs or allocations where the costs or allocation method have been determined by FERC or resolved by a settlement accepted by FERC or in the context of other True-up Adjustments, except that such information requests shall be permitted if they seek to determine if there has been a material change in circumstances. Interested Parties shall make good faith efforts to submit consolidated sets of information requests that limit the number and overlap of questions to the maximum extent practicable.

c. VEPCO shall make a good faith effort to respond to the Information Requests within fifteen (15) business days of receipt of such requests. VEPCO may give reasonable priority to responding to Information Requests that satisfy the practicable coordination and consolidation provision of Section 2.b. above.

Section 3 Challenges to True-Up Adjustments

a. No later than December 2 of each year, any Interested Party may notify VEPCO in writing of any specific challenges to any component of the most recently-posted True-Up Adjustment and any Material Accounting Change identified pursuant to Section 1.a(iii), above that affects the True-Up Adjustment ("Preliminary Challenge"). VEPCO shall promptly cause the Preliminary Challenge to be posted on the www.PJM.com website. VEPCO and the

Interested Party shall make good faith efforts to resolve the Preliminary Challenge through negotiations. Any modification to the True-Up Adjustment or any Material Accounting Change that results from such negotiations and that is agreed upon no later than December 18 shall be promptly posted on the website and incorporated into the Annual Update for the next calendar year.

b. Any Interested Party that has not resolved its Preliminary Challenge to a True-Up Adjustment or a Material Accounting Change that affects the True-Up Adjustment may file with the FERC a Complaint pursuant to 18 C.F.R. § 385.206.

c. An Interested Party's failure to make a Preliminary Challenge with respect to a component of the True-Up Adjustment or a Material Accounting Change that affects that True-Up Adjustment shall not bar the Interested Party from making a Preliminary Challenge related to a subsequent True-Up Adjustment or to the same Material Accounting Change to the extent such Material Accounting Change affects a subsequent True-Up Adjustment.

d. In any Complaint proceeding or proceeding initiated *sua sponte* by the FERC challenging a True-Up Adjustment or a Material Accounting Change, VEPCO shall bear the burden of proving that it has reasonably calculated the True-Up Adjustment and/or reasonably adopted and applied the Material Accounting Change.

e. Any changes to the data inputs, including but not limited to revisions to VEPCO's FERC Form No. 1, resulting from Preliminary Challenges or proceedings before the FERC, including proceedings initiated pursuant to Section 3.b above and proceedings initiated *sua sponte* by the FERC, that are not agreed upon no later than December 18 shall be incorporated into the Formula Rate and the True-Up Adjustment for the next calendar year that commences after the negotiations or proceedings become final. This reconciliation mechanism shall apply in lieu of mid-year adjustments, refunds or surcharges to rates. However, in the event that the Formula Rate is replaced by a stated rate for VEPCO, actual refunds or surcharges (with interest determined in accordance with 18 C.F.R. §35.19a) shall be made no later than thirty (30) days after the effective date of the stated rate established by FERC.

Section 4 Proceedings to Modify the Formula Rate or Stated Components of the Formula Rate

a. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of VEPCO to file unilaterally, pursuant to Section 205 of the Federal Power Act and the regulations thereunder, to modify the Formula Rate or stated components of the Formula Rate (including, but not limited to, the rate of return on equity, the depreciation rates and Post-Employment Benefits other than Pensions ("PBOP")); or to replace the Formula Rate with a stated rate; or the right of any other entity to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder.

WITNESS DIRECT TESTIMONY SUMMARY

Witness: William J. Caffall

Title: Regulatory Analyst III

Summary:

Company Witness William J. Caffall explains the rate design and cost allocation for Rider T1 and specifically discusses and sponsors the development of the tariff and associated rates to be effective for usage on and after September 1, 2025.

Mr. Caffall discusses the rate design of the Rider T1 RAC consistent with what was approved in the Company's 2024 Rider T1 proceeding, Case No. PUR-2024-00071 (the "2024 Rider T1"), and proposes one adjustment.

Next, Mr. Caffall shows the impact Rider T1 will have on customer bills at representative levels of consumption. As Mr. Caffall testifies, for a typical residential customer using 1,000 kWh per month, the proposed Rider T1, once effective for billing purposes for usage on and after September 1, 2025 will increase the monthly bill by $2.10.

Finally, Mr. Caffall testifies that the Company requests for billing purposes, a rate effective date for usage on and after September 1, 2025, or the first day of the month which is at least fifteen (15) calendar days following the date of any Commission order approving Rider T1.

Mr. Caffall sponsors the following schedules:

- Schedule 1 – Allocation of Subsection A 4 revenue requirement to customer classes
- Schedule 2 – Rate Design
- Schedule 3 – Derivation of the Rider T1 rates showing the Subsection A 4 cost of service, the existing Subsection A 4 component of base rates, and the calculation of the Rider T1 rates
- Schedule 4 – Breakdown between the Subsection A 4 component of base rates and Rider T1
- Schedule 5 – Proposed Rider T1 tariff sheet
- Schedule 6 – Impact of the proposed rider to the typical bills
- Filing Schedule 46C, Statement 1 – Methodology and derivation of the A 4 rate adjustment clause recovery factors (the Subsection A 4 component of base rates plus Rider T1) and the derivation of the Rider T1 rates
- Filing Schedule 46C, Statement 2 – Annual revenue requirement by class for the Rate Year September 1, 2025 through August 31, 2026 and for calendar years 2025-2034

DIRECT TESTIMONY
OF
WILLIAM J. CAFFALL
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2025-00076

Q. Please state your name, position of employment with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), and business address.

A. My name is William J. Caffall and I am a Regulation Rate Design Regulatory Analyst III for the Company. My business address is 120 Tredegar Street, Richmond, Virginia 23219. A statement of my background and qualifications is attached as Appendix A.

Q. Mr. Caffall, what is the purpose of your testimony in this case?

A. I am testifying in support of the Company's application for approval of an updated rate adjustment clause ("RAC") pursuant to § 56-585.1 A 4 of the Code of Virginia ("Subsection A 4"), designated Rider T1.

Specifically, the purpose of my testimony is to discuss and sponsor the updated Rider T1 based on the revenue requirement presented by Company Witness David M. Wilkinson, to become effective for usage on and after September 1, 2025. Following a presentation of the twelve-monthly coincident peak ("12-CP") methodology for allocating costs in Rider T1 as directed by the Commission's Final Order in the 2021 Rider T1 proceeding, Case No. PUR-2021-00102, I discuss the plan to continue fully allocating the cost of Network Integration Transmission Service ("NITS") and other demand-related components of the jurisdictional revenue requirement to the customer classes. I will discuss the rate design of the Rider T1 RAC, consistent with what was approved in the

Company's 2024 Rider T1 proceeding, Case No. PUR-2024-00071 (the "2024 Rider T1"). And consistent with the 2024 Rider T1 proceeding, we recognize revenue from transmission standby charges for the residential class and make an adjustment for such revenue when calculating the residential Rider T1 energy charge. In addition, I will discuss the impact that the Rider T1 rates will have on typical customer bills at representative levels of consumption. Finally, the Company respectfully requests for billing purposes, a rate effective date for usage on and after September 1, 2025. However, if the Commission issues an order that is not at least fifteen (15) days prior to this proposed effective date, the Company respectfully requests, for billing purposes, a rate effective date for usage on and after the first day of the month which is at least fifteen (15) days following the date of any Commission order approving Rider T1.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, WJC, consisting of Schedules 1-6, was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief. I am also sponsoring Filing Schedule 46C, Statements 1 and 2, which detail the Company's methodology for allocating the revenue requirement among the customer rate classes and the design of the class rate schedules, as well as Rider T1's annual revenue requirement filing by customer class over the duration of the RAC.

Q. How is your testimony organized?

A. My testimony will address two primary areas:

I. Class Allocation of Transmission Revenue Requirement

II. Rate Design

I. CLASS ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT

Q. Please discuss any changes the Company proposes to the methodology used to allocate the revenue requirement to the customer classes to calculate Rider T1 rates compared to the methodology that was used in the 2024 Rider T1 proceeding.

A. In the 2021 Rider T1 Final Order, the Commission adopted the Hearing Examiner's finding and recommendation regarding cost allocation that provided for a three-year transition from using the 1-CP allocation method to the 12-CP allocation method for allocation of NITS and other demand-related components of the revenue requirement to the customer classes.[1] The 2023 Rider T1 filing completed the three-year transition to the 12-CP method for the proposed rate year. Consistent with the 2024 Rider T1 filing, this filing utilizes a full 12-CP allocation method for the projected rate year portion of the revenue requirement related primarily to NITS and Transmission Enhancement. The 2024 True-up Adjustment portion of the revenue requirement utilizes a full 12-CP allocation method.

[1] *Application of Virginia Electric and Power Company for approval of a rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia*, Case No. PUR-2021-00102, Final Order at 7-8 (Aug. 16, 2021).

Q. Please discuss the Company's proposed allocation of NITS and other demand-related components of the jurisdictional revenue requirement determined by Company Witness Wilkinson to the customer classes.

A. Table 1 below summarizes how the components of the revenue requirement were allocated utilizing the 12-CP allocation of NITS and other demand-related components of the revenue requirement to the customer classes. The allocation factors for each customer class are calculated as follows:

Table 1

Allocation Method	Total VA Juris	Residential	GS-1	GS-2	GS-3	GS-4	Church	Outdoor Lighting
12-CP	100.0000%	48.2747%	5.1501%	12.7146%	11.9423%	21.5663%	0.3376%	0.0145%

This impacts the NITS, the Transmission Enhancement Charges / Credits ("TMEC"), and the Update components of the revenue requirement. The True-Up Adjustment for 2024 fully utilizes the 12-CP method.

II. RATE DESIGN

Q. Does the Company propose changes to rate design for Rider T1 as compared to the 2024 Rider T1?

A. No, the rate design for this Rider T1 filing is consistent with the 2024 Rider T1 filing.

Q. Mr. Caffall, would you please discuss the methodology used for calculating the Rider T1 rates?

A. As discussed above, the Company has calculated the Rider T1 rates utilizing the 12-CP method for NITS and other demand-related components and for the allocation of the jurisdictional revenue requirement to the customer classes. The following discussion describes the methodology used to design the Rider T1 rates.

Page 1 of Schedule 1 details the allocation to the customer classes of the deferred cost adjustment provided by Company Witness Wilkinson. This involves the true-up of the 2024 costs using the composite allocation factors determined from the 2023 demand and 2024 energy allocation factors. The true-up adjustment is then carried over to page 2 along with the new Subsection A 4 total revenue requirement provided by Company Witness Wilkinson. These totals are then allocated to the customer classes using a composite allocation factor calculated from the 2024 energy and demand allocation factors. The final composite allocation factors will be used as the input to the tariff design. Pages 3 and 4 of Schedule 1 show the derivation of the Schedule MBR and Schedule SCR Rider T1 charges.

My Schedule 2 details the Rider T1 rate design methodology. In order to develop Rider T1 rates applicable to each of its rate schedules, the Company must first determine the forecasted kWh sales for each of the rate schedules. For the Virginia jurisdiction, the Company forecasts kWh sales and customers by "Revenue Class" (Residential, Commercial, and Industrial are the Company's revenue classes), and this Revenue Class kWh sales forecast is shown on my Schedule 2, page 1. Accordingly, the Company's forecasted kWh sales for each Revenue Class must then be allocated to the rate schedule level. After considering forecasted customers and usage for the Company's Market Based Rate schedules, the allocation of the remaining forecasted usage was performed using 2022-2024 historical monthly customer and kWh usage for each rate schedule to capture the recent trends of kWh sales and the number of customers within each rate schedule. This allocation by revenue class (and within revenue class by rate schedule) is shown on page 2 of my Schedule 2.

During this allocation process, those rate schedules serving very small populations (*i.e.*, Rate Schedules DP-R, 1EV, EV, DP-1, and DP-2) are represented by the primary alternative tariff (*i.e.*, Rate Schedule 1 (for DP-R, 1EV, and EV), Rate Schedule GS-1 (for DP-1), and Rate Schedule GS-2 (for DP-2)). The summary on page 3 of my Schedule 2 shows the allocation of the forecasted kWh sales for the twelve months ending August 31, 2026, for each rate schedule. Pages 4 and 5 of my Schedule 2 categorize the forecasted rate schedule kWh sales into the seven customer classes (*i.e.*, the Residential, GS-1, GS-2, GS-3, GS-4, Church, and Outdoor Lighting customer classes).

The next step is to allocate the Virginia jurisdictional revenue requirement sponsored by Company Witness Wilkinson to these customer classes. As discussed in detail earlier in this testimony, I do this using the 12-CP method.

Page 6 of my Schedule 2 shows the detailed allocation of the combined revenue requirement among the customer classes using the 12-CP methodology, along with the resulting average rate per kWh by customer class based on forecasted sales for the twelve months ending August 31, 2026. Next, the relevant customer class rate, as determined by the Company on page 6, was applied to the forecasted kWh sales for the twelve months ending August 31, 2025, for each schedule within the associated customer class to determine a rate schedule-specific revenue requirement, as shown on page 7 of my Schedule 2. The resulting "all in" transmission rates (the Subsection A 4 component of base rates plus Rider T1) per kWh are shown on page 8 of my Schedule 2.

The Rate Schedule GS-2 rate is billed on a demand basis when the customer's monthly kWh usage exceeds 200 kWh per kilowatt ("kW") of demand and on an energy basis when the customer's monthly kWh usage does not exceed 200 kWh per kW of demand. Rate Schedules GS-2T, GS-3, GS-4, 8, and 10 are billed on a demand basis. The calculations for the development of the demand charges applicable to these rate schedules are shown on page 9 of my Schedule 2. In addition, as a result of the Commission's rulings in Case No. PUE-2011-00088 and Case No. PUR-2022-00065, a small number of net-metered accounts on Rate Schedules 1, 1G, and 1S are subject to a minimum Subsection A 4 charge per kW (applicable beginning July 1, 2020, to net metered installations greater than 15 kW based on a change in the Code of Virginia). To calculate the Rider T1 standby charge applicable to these rate schedules, the Company has simply adjusted the minimum rate per kW in proportion to the change in the Rate Schedule 1 energy rate (with the resulting rate shown on my Schedule 3).

Q. Please describe the adjustment to the rate design of residential Rider T1 energy charges based on consideration of transmission revenues resulting from the applicability of standby charges.

A. In past Rider T1 proceedings prior to the 2023 Rider T1 filing, because the additional revenue associated with this minimum charge from standby charges was not material, the Company simply adjusted the minimum rate per kW in proportion to the change in the Rate Schedule 1 energy rate and made no adjustment to Rider T1 energy charges for such revenue. As noted in previous Rider T1 proceedings, the Company believes the minimum charge revenue resulting from the base transmission and Rider T1 standby charges is material.

The Company has determined an average minimum charge revenue per bill based upon the application of the minimum charge provision related to standby charges for base transmission and Rider T1. After consideration of the additional revenue associated with these minimum charges, the Company has determined that an additional adjustment is needed to the Rider T1 energy charge for the residential class consistent with the Company's proposed adjustment made in the 2023 Rider T1 proceeding.

Initially, I calculate the residential Rider T1 energy charge to be $0.011793 per kWh. Taking into account an estimate of minimum charge revenues resulting from the base transmission and Rider T1 standby charges for the September 2025 through August 2026 rate period, I then calculate an adjustment to the Rider T1 energy charge of ($0.000004) per kWh. This adjustment is shown on my Schedule 3. The resulting residential Rider T1 energy charge is $0.011789 per kWh.

Q. Mr. Caffall, do you have an exhibit showing the derivation of Rider T1?

A. Yes. Schedule 3 shows the derivation of Rider T1 for each of the Company's Virginia jurisdiction retail rate schedules. Columns (2) and (3) show the Subsection A 4 cost of service rate by billing determinant, kWh or kW. Columns (4) and (5) show the existing Subsection A 4 component of base rates approved in Case No. PUE-2011-00044 by billing determinant, kWh or kW. Columns (6) and (7) provide the calculation that results from subtracting the existing Subsection A 4 component of base rates from the Subsection A 4 cost of service rate by billing determinant and is labeled as Rider T1 Before Adjustment for Standby Charge Revenue.

As I described above, the Company is making an adjustment to the Rider T1 energy charge for the residential class due to the minimum charge revenues the Company anticipates will result from the base transmission and Rider T1 standby charges for the September 2025 through August 2026 rate period. The per kWh adjustment shown in column (8) is labeled as Adjustment for Residential Class Standby Charge Revenue. The adjustment will serve to reduce the Rider T1 energy charge for the residential class. Finally, columns (9) and (10) provide the Rider T1 After Adjustment for Standby Charge Revenue on a per kWh or per kW basis, as appropriate, for each rate schedule.

Q. Do you have an exhibit that shows the revenue breakdown between the Subsection A 4 component of base rates and Rider T1?

A. Yes. Schedule 4 shows the proposed Subsection A 4 revenue requirement breakdown between the Subsection A 4 component of base rates and Rider T1. The Company forecasts collection of $560,916,458 through the Subsection A 4 component of base rates and proposes a $782,419,277 revenue requirement through Rider T1. Thus, the net total Subsection A 4 revenue requirement is $1,343,335,735.

Q. Do you have an exhibit showing the Company's proposed Rider T1 effective September 1, 2024?

A. Yes. My Schedule 5 Tariff Sheet shows the Company's proposed Rider T1, which, if approved as proposed, would be applicable for usage on and after September 1, 2025.

Q. Do you propose any language changes for the Rider T1 tariff?

A. No.

Q. Mr. Caffall, would you explain how Rider T1 will affect customers' bills?

A. My Schedule 6 Typical Bills provides typical bill impacts for customers taking service under Rate Schedules 1, GS-1, GS-2, GS-3, GS-4, and 5C based on the proposed Rider T1 and rates, pending Commission approval, to be effective on September 1, 2025. As shown on my Typical Residential bill for Schedule 1, for a residential customer using 1,000 kWh per month, the base transmission charge is $9.70, the Rider T1 charge is $11.79 for total transmission cost recovery of $21.49. This represents an increase of $2.10 on the total bill of a typical residential customer using 1,000 kWh per month.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

**BACKGROUND AND QUALIFICATIONS
OF
WILLIAM J. CAFFALL**

William "Bill" Caffall received a Bachelor of Liberal Arts Degree with an emphasis in Communication from Bethany College in 1998. He then joined the Company in 1998 as a Payment Processing Analyst before holding positions as a System Service Group Budget Analyst, multiple Data Management and Billing positions with Dominion Energy Solutions, and Senior Energy Market Analyst in the Company's Integrated Strategic Planning Team. His current position is Regulatory Analyst III in the Customer Rates Department with responsibilities that include providing support and analysis for the Company's regulatory filings in Virginia and North Carolina.

Mr. Caffall has previously provided testimony before the State Corporation Commission of Virginia and the North Carolina Utilities Commission.

Company Exhibit No. __
250510019
Witness: WJC
Schedule 1
Page 1 of 4

FOR THE 2024 TRUE-UP

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT TO CUSTOMER CLASSES

Line No.	A. DEFERRED COST ADJUSTMENT	Virginia Jurisdiction	Witness: DMW Formula Schedule 9 Column 16	Allocation Basis
1	Network Integrated Transmission Service	($1,020,511,036)	Page 1, Line 5	2023 NSPL
2	Underground Transmission Service (Docket EL10-49)	($8,533,551)	Page 1, Line 7	2023 NSPL
3	Transmission Enhancement Charges/Credits	$47,012,280	Page 1, Line 15	2023 NSPL
4	PJM Administrative Charges - Current	($20,850,773)	Page 1, Line 21	2023 kWh
5	Economic/Emergency Load Response Programs	($1,053,987)	Page 1, Line 23	2023 kWh
6	Subtotal Costs Subject to Deferral	($1,003,937,067)	Page 1, Line 24	Composite
7	Amortization of Actual Over/Under Recovered Costs	($135,125,767)	Page 1, Line 25	Composite
8	Subsection A4 Costs Monthly Update Amount	$65,852,217	Page 1, Line 26	Composite
9	Total Costs Subject to Deferral	($1,073,210,616)	Page 1, Line 27	
10	Total Subsection A4 Revenues	$935,370,890	Page 1, Line 28	Composite
11	Total Monthly (Under)/Over Recovery	($137,839,726)	Page 1, Line 29	Composite

B. REVENUE REQUIREMENT BY CUSTOMER CLASS

Line No.	12CP ALLOCATION	VA JURIS	RESIDENTIAL	GS-1	GS-2	GS-3	GS-4	CHURCH	OD LIGHTS
12	Class Demand at Time of 2023 System Peak (12 CP Demand)	12,932,596	6,287,249	638,665	1,717,156	1,637,350	2,608,867	43,310	0
13	Class Allocation Factors (12 CP)	100.0000%	48.6155%	4.9384%	13.2777%	12.6606%	20.1728%	0.3349%	0.0000%
14	Revenue Requirement Allocated To Classes	($982,032,307)	($477,420,108)	($48,496,820)	($130,391,631)	($124,331,617)	($198,103,401)	($3,288,730)	$0
	ENERGY ALLOCATION								
15	2024 MWh	81,225,006	30,195,594	4,016,055	10,774,090	11,659,997	24,270,896	219,175	89,199
16	Factor 3 - Energy	100.0000%	37.1752%	4.9444%	13.2645%	14.3552%	29.8811%	0.2698%	0.1098%
17	Revenue Requirement Allocated To Classes	($21,904,760)	($8,143,148)	($1,083,050)	($2,905,557)	($3,144,468)	($6,545,375)	($59,107)	($24,055)
	SUBTOTAL COSTS SUBJECT TO DEFERRAL								
18	Subtotal Subject to Deferral	($1,003,937,067)	($485,563,256)	($49,579,869)	($133,297,187)	($127,476,085)	($204,648,776)	($3,347,837)	($24,055)
19	Composite Class Allocation Factors	100.0000%	48.3659%	4.9385%	13.2774%	12.6976%	20.3846%	0.3335%	0.0024%
	TOTAL COST SUBJECT TO DEFERRAL								
20	Total Subject to Deferral	($1,073,210,616)	($519,068,036)	($53,000,974)	($142,494,944)	($136,272,175)	($218,769,927)	($3,578,844)	($25,715)
21	Composite Class Allocation Factors	100.0000%	48.3659%	4.9385%	13.2774%	12.6976%	20.3846%	0.3335%	0.0024%
	TOTAL MONTHLY (UNDER)/OVER RECOVERY								
22	Total Monthly (Under)/Over Recovery	($137,839,726)	($66,667,432)	($6,807,275)	($18,301,593)	($17,502,361)	($28,098,107)	($459,655)	($3,303)
23	Composite Class Allocation Factors	100.0000%	48.3659%	4.9385%	13.2774%	12.6976%	20.3846%	0.3335%	0.0024%

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT TO CUSTOMER CLASSES

Line No.	A. TRANSMISSION REVENUE REQUIREMENT	Virginia Jurisdiction	Witness: DMW Formula Schedules	Allocation Basis
1	Network Integrated Transmission Service	$1,174,910,474	Formula Schedule 2; pg 1 of 2; Col. 9; Line 5	2024 NSPL
2	Transmission Enhancement Charges/Credits	($73,135,755)	Formula Schedule 2; pg 1 of 2; Col. 9; Line 32	2024 NSPL
3	PJM Administrative Charges - Current	$20,212,445	Formula Schedule 2; pg 1 of 2; Col. 9; Line 38	2024 kWh
4	Demand Response Programs Approved by FERC	$926,758	Formula Schedule 2; pg 1 of 2; Col. 9; Line 41	2024 kWh
5	True-Up Adjustment	$137,839,726	Formula Schedule 9; pg 1 of 1; Col. 16; Line 29	Composite
6	Update - January 2025 - August 2025	$82,582,087	Formula Schedule 10; pg 1 of 1; Col. 12; Line 15	2024 NSPL
7	Total	$1,343,335,735		
8	Revenue Requirement Allocated On NSPL	$1,184,356,807		
9	Revenue Requirement Allocated On Energy	$21,139,203		
10	Revenue Requirement Allocated On Composite	$137,839,726		
11	Total	$1,343,335,735		

B. **REVENUE REQUIREMENT BY CUSTOMER CLASS**

Line No.	12CP ALLOCATION	VA JURIS	RESIDENTIAL	GS-1	GS-2	GS-3	GS-4	CHURCH	OD LIGHTS
12	Class Demand at Time of 2024 System Peak (12 CP Demand)	13,313,512	6,452,017	689,430	1,682,736	1,572,498	2,869,781	45,165	1,884
13	Class Allocation Factors (12 CP)	100.0000%	48.4622%	5.1784%	12.6393%	11.8113%	21.5554%	0.3392%	0.0142%
14	Revenue Requirement Allocated To Classes	$1,184,356,807	$573,965,077	$61,331,026	$149,694,540	$139,887,901	$255,292,847	$4,017,816	$167,599
	ENERGY ALLOCATION								
15	2024 MWh	81,225,006	30,195,594	4,016,055	10,774,090	11,659,997	24,270,896	219,175	89,199
16	Class Allocation Factors (Energy)	100.0000%	37.1752%	4.9444%	13.2645%	14.3552%	29.8811%	0.2698%	0.1098%
17	Revenue Requirement Allocated To Classes	$21,139,203	$7,858,550	$1,045,198	$2,804,009	$3,034,571	$6,316,619	$57,041	$23,215
	TRUE UP ALLOCATION								
18	Class Allocation Factors for 2024 True-Up (1)	100.0000%	48.3659%	4.9385%	13.2774%	12.6976%	20.3846%	0.3335%	0.0024%
19	Revenue Requirement Allocated To Classes	$137,839,726	$66,667,432	$6,807,275	$18,301,593	$17,502,361	$28,098,107	$459,655	$3,303
	12CP ALLOCATION								
20	**Total Revenue Requirement to Customer Classes**	**$1,343,335,735**	**$648,491,059**	**$69,183,499**	**$170,800,142**	**$160,424,833**	**$289,707,573**	**$4,534,513**	**$194,116**
21	Weighted Average Allocation	100.0000%	48.274682358%	5.150127192%	12.714628049%	11.942273901%	21.566282019%	0.337556177%	0.014450305%
22	12 Months Ending August 2026 kWh Sales	86,611,389,895	30,171,817,825	4,354,075,183	12,140,615,635	13,546,507,077	26,057,440,783	241,923,482	99,009,910
23	***Class Revenue Requirement Per kWh***		***$0.02149327***	***$0.01588937***	***$0.01406849***	***$0.01184252***	***$0.01111804***	***$0.01874358***	***$0.00196057***

Note:
(1) Class allocation factor for 2024 True-Up from Schedule 1, Page 1 line 24

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
DERIVATION OF SCHEDULE MBR AND SCHEDULE SCR CHARGES

Line No.		Schedule MBR, SCR Secondary	Schedule MBR, SCR Primary and Transmission
1	Class Demand Average of 2024 12CP kW	1,572,498	2,869,781
2	Revenue Requirement Allocated To Classes	$139,887,901	$255,292,847
3	Revenue Requirement for 12CP Allocation / System Peak Demand	88.959	88.959
4	Monthly Revenue Requirement per kW	7.413	7.413
5	Revenue Requirement for Energy Allocation / kWh	$ 0.000260	$ 0.000260
6	True-up Adjustment for 2024 (Under) / Over Recovery Based on 12 CP Demand (1)	($17,070,628)	($27,199,432)
7	True-up Adjustment for 2024 (Under) / Over Recovery Based on Energy (2)	($431,733)	($898,675)
8	True-up Adjustment for 2024 (Under) / Over Recovery Total	($17,502,361)	($28,098,107)
9	True-Up Adjustment per 12CP kW (Line 6 / Line 1)	($10.856)	($9.478)
10	Monthly True-Up Adjustment per 12CP kW (Line 9 / 12)	($0.905)	($0.790)
11	True-Up Adjustment Allocated to Energy Per kWh (Line 7 / Sch. 1, pg 2 Line 15 * 1,000)	$ (0.000037)	$ (0.000037)
12	Monthly Cost Recovery Rate Transmission Rate for NITS, True-Up 2024 Transmission Enhancement and Update per 12CP kW (Line 4 + Line 10 * -1)	$8.318	$8.203
13	Monthly Cost Recovery Rate for PJM Administrative Charges and Demand Response Programs Approved by FERC per kWh (Line 5 + Line 11 * -1)	$ 0.000297	$ 0.000297
14	Schedule MBR and Schedule SCR - Primary Rate per 12CP kW (Line 12)		$8.203
15	Transmission to Primary Ratio		0.983579
16	Schedule MBR and Schedule SCR - Transmission Rate per 12CP kW (Line 14 * Line 15)		$8.068

Notes:
(1) From Schedule 1, pg 1, Line 22 * (Line 14 / Line 18)
(2) From Schedule 1, pg 1, Line 22 * (Line 17 / Line 18)

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
SCHEDULES MBR SECONDARY, MBR PRIMARY, AND MBR TRANSMISSION
AND SCHEDULES SCR SECONDARY, SCR PRIMARY, AND SCR TRANSMISSION

The following will be the Rider T1 charges for Schedule MBR and Schedule SCR and will be stated in the Rider T1 tariff.

		(1)			(2)		
	Schedule	Monthly Transmission Cost Recovery Rate for NITS, Transmission Enhancement and Update per 12CP kW			Monthly Cost Recovery Rate for PJM Administrative Charges and Demand Response Programs Approved by FERC per kWh		
1	MBR, SCR Secondary	$	8.318	(1)	$	0.000297	(3)
2	MBR, SCR Primary	$	8.203	(1)	$	0.000297	(3)
3	MBR, SCR Transmission	$	8.068	(2)	$	0.000297	(3)

Notes:

(1) From Schedule 1 Page 3, Line 12
(2) From Schedule 1 Page 3, Line 16
(3) From Schedule 1 Page 3, Line 13

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
FORECAST KWH SALES AND CUSTOMERS BY REVENUE CLASS
12 MONTHS ENDED AUGUST 31, 2026

REVENUE CLASS=A. RESIDENTIAL

YR	MONTH	FORECAST CUST	FORECAST KWH
2025	9	2,381,609	2,387,207,795
2025	10	2,383,939	1,677,707,345
2025	11	2,387,594	2,025,058,285
2025	12	2,391,617	2,855,872,497
2026	1	2,387,908	3,399,122,484
2026	2	2,390,277	2,822,505,977
2026	3	2,392,187	2,353,799,686
2026	4	2,393,221	1,809,508,910
2026	5	2,394,890	1,946,089,582
2026	6	2,397,224	2,698,239,831
2026	7	2,399,977	3,233,743,095
2026	8	2,403,406	2,986,897,634
TOTAL			30,195,753,120

REVENUE CLASS=B. COMMERCIAL

YR	MONTH	FORECAST CUST	FORECAST KWH
2025	9	231,212	4,262,419,870
2025	10	231,259	4,060,332,596
2025	11	231,306	4,135,284,282
2025	12	231,353	4,365,803,393
2026	1	231,400	4,381,242,581
2026	2	231,447	3,972,210,549
2026	3	231,494	4,181,550,950
2026	4	231,542	4,121,199,772
2026	5	231,590	4,387,359,246
2026	6	231,637	4,672,086,770
2026	7	231,685	5,007,506,987
2026	8	231,734	4,993,147,709
TOTAL			52,540,144,707

REVENUE CLASS=C. INDUSTRIAL

YR	MONTH	FORECAST CUST	FORECAST KWH
2025	9	582	348,839,375
2025	10	581	278,048,396
2025	11	581	392,730,802
2025	12	580	309,316,569
2026	1	580	339,460,541
2026	2	581	366,923,335
2026	3	580	328,541,341
2026	4	580	273,041,352
2026	5	579	273,863,503
2026	6	579	256,339,777
2026	7	579	365,845,110
2026	8	578	342,541,965
TOTAL			3,875,492,069
			86,611,389,895

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
FORECAST KWH SALES BY REVENUE CLASS AND RATE SCHEDULE
12 MONTHS ENDED AUGUST 31, 2026

SCH SEQ NO.=A. RESIDENTIAL

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
1	29,804,554,297
1G	207,831,496
1P	14,548,977
1S	136,905,966
1T	7,681,374
1W	295,714
24	2,734,554
27	17,632,949
28	3,532,831
29	34,961
TOTAL	30,195,753,120

SCH SEQ NO.=B. COMMERCIAL

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
GS1	4,343,101,134
GS2	9,804,826,074
GS2T	2,224,703,556
GS3	10,746,855,582
GS4	22,609,494,695
5	23,020,438
5C	184,287,034
5P	57,636,448
6	3,306,902
6TS	144,127,151
7	6,729,207
10	2,318,490,929
24	6,486,414
25	111,355
27	44,273,661
28	18,383,900
29	4,310,229
TOTAL	52,540,144,707

SCH SEQ NO.=C. INDUSTRIAL

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
GS1	4,244,842
GS2	79,214,142
GS2T	8,831,094
GS3	429,904,715
GS4	2,382,467,577
5	20,332
6TS	939,591
10	968,360,718
24	11,992
27	1,081,950
28	415,115
TOTAL	3,875,492,069
	86,611,389,895

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
SUMMARY OF FORECAST KWH SALES BY RATE SCHEDULE
12 MONTHS ENDED AUGUST 31, 2026

RATE SCHEDULE	12 MONTHS ENDED 12 MOS ENDED 08/31/2026 FORECAST KWH TOT FORECAST KWH	2023 MICRON KWH	12 MOS ENDED 08/31/2025 FORECAST KWH
1	29,804,554,297	0	29,804,554,297
1G	207,831,496	0	207,831,496
1P	14,548,977	0	14,548,977
1S	136,905,966	0	136,905,966
1T	7,681,374	0	7,681,374
1W	295,714	0	295,714
GS1	4,347,345,977	0	4,347,345,977
GS2	9,884,040,216	0	9,884,040,216
GS2T	2,233,534,649	0	2,233,534,649
GS3	11,176,760,297	0	11,176,760,297
GS4	24,991,962,272	0	24,991,962,272
5	23,040,769	0	23,040,769
5C	184,287,034	0	184,287,034
5P	57,636,448	0	57,636,448
6	3,306,902	0	3,306,902
6TS	145,066,742	0	145,066,742
7	6,729,207	0	6,729,207
10	3,286,851,647	0	3,286,851,647
24	9,232,959	0	9,232,959
25	111,355	0	111,355
27	62,988,560	0	62,988,560
28	22,331,846	0	22,331,846
29	4,345,190	0	4,345,190
	=================	==============	==============
	86,611,389,895	0	86,611,389,895

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
SUMMARY OF FORECAST KWH SALES
RATE SCHEDULES CATEGORIZED INTO CUSTOMER CLASSES
12 MONTHS ENDED AUGUST 31, 2026

CUSTOMER CLASS=A. RES

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
1	29,804,554,297
1G	207,831,496
1P	14,548,977
1S	136,905,966
1T	7,681,374
1W	295,714
--------	-------------
CLASS	30,171,817,825

CUSTOMER CLASS=B. GS-1

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
7	6,729,207
GS1	4,347,345,977
--------	-------------
CLASS	4,354,075,183

CUSTOMER CLASS=C. GS-2

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
5	23,040,769
GS2	9,884,040,216
GS2T	2,233,534,649
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CLASS	12,140,615,635

CUSTOMER CLASS=D. GS-3

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
10	2,221,373,136
6	3,306,902
6TS	145,066,742
GS3	11,176,760,297
--------	-------------
CLASS	13,546,507,077

CUSTOMER CLASS=E. GS-4

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
10	1,065,478,511
GS4	24,991,962,272
--------	-------------
CLASS	26,057,440,783

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
SUMMARY OF FORECAST KWH SALES
RATE SCHEDULES CATEGORIZED INTO CUSTOMER CLASSES
12 MONTHS ENDED AUGUST 31, 2026

CUSTOMER CLASS=F. CHURCH

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
5C	184,287,034
5P	57,636,448
CLASS	241,923,482

CUSTOMER CLASS=G. OD LIGHT

RATE SCHEDULE	12 MOS ENDED 08/31/2025 FORECAST KWH
24	9,232,959
25	111,355
27	62,988,560
28	22,331,846
29	4,345,190
CLASS	99,009,910
	86,611,389,895

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
ALLOCATION OF VIRGINIA JURISDICTIONAL REVENUE REQUIREMENT TO THE CUSTOMER CLASSES AND
CALCULATION OF A 4 RATE ADJUSTMENT CLAUSE CUSTOMER CLASS RECOVERY FACTORS

CUSTOMER CLASS	VA JURIS REVENUE REQUIREMENT	CUST CLASS ALLOCATION FACTOR	CUST CLASS ALLOCATED REVENUE REQ	12 MOS ENDED 08/31/2025 FORECAST KWH	CUSTOMER CLASS RATE
A. RES	$1,343,335,735	0.48274682	$648,491,059	30,171,817,825	$.02149327
B. GS-1	$1,343,335,735	0.05150127	$69,183,499	4,354,075,183	$.01588937
C. GS-2	$1,343,335,735	0.12714628	$170,800,142	12,140,615,635	$.01406849
D. GS-3	$1,343,335,735	0.11942274	$160,424,833	13,546,507,077	$.01184252
E. GS-4	$1,343,335,735	0.21566282	$289,707,573	26,057,440,783	$.01111804
F. CHURCH	$1,343,335,735	0.00337556	$4,534,513	241,923,482	$.01874358
G. OD LIGHT	$1,343,335,735	0.00014450	$194,116	99,009,910	$.00196057
		==========	============	==============	
		1.00000000	$1,343,335,735	86,611,389,895	

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
CALCULATION OF REVENUE REQUIREMENT BY RATE SCHEDULE

RATE SCHEDULE	CUSTOMER CLASS	12 MOS ENDED 08/31/2025 FORECAST KWH	CUSTOMER CLASS RATE	REVENUE REQ BY SCHEDULE AND CLASS
1	RES	29,804,554,297	$.02149327	$640,597,365
1G	RES	207,831,496	$.02149327	$4,466,979
1P	RES	14,548,977	$.02149327	$312,705
1S	RES	136,905,966	$.02149327	$2,942,557
1T	RES	7,681,374	$.02149327	$165,098
1W	RES	295,714	$.02149327	$6,356
GS1	GS-1	4,347,345,977	$.01588937	$69,076,576
GS2	GS-2	9,884,040,216	$.01406849	$139,053,531
GS2T	GS-2	2,233,534,649	$.01406849	$31,422,462
GS3	GS-3	11,176,760,297	$.01184252	$132,361,050
GS4	GS-4	24,991,962,272	$.01111804	$277,861,544
5	GS-2	23,040,769	$.01406849	$324,149
5C	CHURCH	184,287,034	$.01874358	$3,454,199
5P	CHURCH	57,636,448	$.01874358	$1,080,314
6	GS-3	3,306,902	$.01184252	$39,162
6TS	GS-3	145,066,742	$.01184252	$1,717,956
7	GS-1	6,729,207	$.01588937	$106,923
10 S	GS-3	2,221,373,136	$.01184252	$26,306,664
10 P	GS-4	1,065,478,511	$.01111804	$11,846,029
24	OD LIGHT	9,232,959	$.00196057	$18,102
25	OD LIGHT	111,355	$.00196057	$218
27	OD LIGHT	62,988,560	$.00196057	$123,494
28	OD LIGHT	22,331,846	$.00196057	$43,783
29	OD LIGHT	4,345,190	$.00196057	$8,519
		==============		==============
		86,611,389,895		$1,343,335,735

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
REVENUE REQUIREMENT BY RATE SCHEDULE AND
CALCULATION OF RATE PER KWH BY RATE SCHEDULE

RATE SCHEDULE	REVENUE REQ BY REVENUE CLASS	12 MOS ENDED 08/31/2025 FORECAST KWH	RATE BY SCHEDULE (ROUNDED)	SEE NOTES
1	$640,597,365	29,804,554,297	.021493	
1G	$4,466,979	207,831,496	.021493	
1P	$312,705	14,548,977	.021493	
1S	$2,942,557	136,905,966	.021493	
1T	$165,098	7,681,374	.021493	
1W	$6,356	295,714	.021493	
GS1	$69,076,576	4,347,345,977	.015889	
GS2	$139,053,531	9,884,040,216	.014068	*
GS2T	$31,422,462	2,233,534,649	.014068	*
GS3	$132,361,050	11,176,760,297	.011843	*
GS4	$277,861,544	24,991,962,272	.011118	*
5	$324,149	23,040,769	.014068	
5C	$3,454,199	184,287,034	.018744	
5P	$1,080,314	57,636,448	.018744	
6	$39,162	3,306,902	.011843	
6TS	$1,717,956	145,066,742	.011843	
7	$106,923	6,729,207	.015889	
10 S	$26,306,664	2,221,373,136	.011843	*
10 P	$11,846,029	1,065,478,511	.011118	*
24	$18,102	9,232,959	.001961	
25	$218	111,355	.001961	
27	$123,494	62,988,560	.001961	
28	$43,783	22,331,846	.001961	
29	$8,519	4,345,190	.001961	
	==============	==============		
	$1,343,335,735	86,611,389,895		

* THE RATE DESIGN FOR THESE SCHEDULES IS SHOWN ON THE NEXT PAGE OF THIS EXHIBIT AND REFLECTS DEMAND BILLING.

VIRGINIA ELECTRIC AND POWER COMPANY
DETERMINATION OF A 4 RATE ADJUSTMENT CLAUSE RECOVERY FACTORS
RATE DESIGN FOR RATE SCHEDULES GS-2, GS-2T, GS-3, GS-4, 8, 10 & 56-235.2 WITH DEMAND BILLING

A. DESIGN FOR GS-2 A 4 RATE ADJUSTMENT CLAUSE

DEMAND BILLING

TOTAL GS-2 REVENUE REQUIREMENT	$139,053,531	
DIVIDED BY TOTAL GS-2 KW DEMANDS	28,380,214	
= GS-2 KW RATE - DEMAND BILLING	$4.900	PER KW

NON-DEMAND BILLING

GS-2 KW RATE - DEMAND BILLING	$4.900/KW	
X GS-2 NON-DEMAND KW UNITS	5,018,904	
= GS-2 NON-DEMAND REVENUE REQ.	$24,592,628	
DIVIDED BY GS-2 NON DEMAND KWH	622,424,544	
= GS-2 KWH RATE - NON-DEM BILLING	$0.039511	PER KWH

B. DESIGN FOR GS-2T A 4 RATE ADJUSTMENT CLAUSE

TOTAL GS-2T REVENUE REQUIREMENT	$31,422,462	
DIVIDED BY TOTAL GS-2T KW DEMANDS	5,381,910	
= GS-2T KW RATE	$5.839	PER ON-PEAK KW

C. DESIGN FOR GS-3 A 4 RATE ADJUSTMENT CLAUSE

TOTAL GS-3 REVENUE REQUIREMENT	$132,361,050	
DIVIDED BY TOTAL GS-3 KW DEMANDS	21,873,787	
= GS-3 KW RATE	$6.051	PER ON-PEAK KW

D. DESIGN FOR GS-4 & SCH 8 A 4 RATE ADJUSTMENT CLAUSE

CALCULATION TO ADJUST KW UNITS FOR RATE DESIGN

PRESENT GS-4 ESS KW CHG - PRIMARY	$8.769	PER ON-PEAK KW
PRESENT GS-4 ESS KW CHG - TRANS.	$8.625	PER ON-PEAK KW
RATIO OF TRANS CHG TO PRIMARY CHG	0.983579	
PRIMARY KW DEMAND UNITS	39,803,508	
TRANSMISSION KW DEMAND UNITS	2,686,962	
ADJ TO TRANSMISSION KW TO REFLECT TRANSMISSION DISCOUNT (X RATIO)	2,642,838	
TOTAL GS-4 KW DEMANDS (ADJUSTED)	42,446,346	

CALCULATION FOR GS-4 & SCH 8 KW PRICING

TOTAL GS-4 REVENUE REQUIREMENT	$277,861,544	
DIVIDED BY ADJUSTED GS-4 KW	42,446,346	
= GS-4 & SCH 8 KW PRICE (PRIMARY)	$6.546	PER ON-PEAK KW
X TRANSMISSION TO PRIMARY RATIO	0.983579	
= GS-4 & SCH 8 KW RATE (TRANSMISSION)	$6.439	PER ON-PEAK KW

F. DESIGN FOR SCH 10 A 4 RATE ADJUSTMENT CLAUSE

CALCULATION OF SCH 10 (SEC VOLT) RATE DESIGN

TOTAL 10 (SEC) REVENUE REQUIREMENT	$26,306,664	
DIVIDED BY 10 (SEC) ES PEAK KW	6,620,191	
= SCH 10 (SEC) ES PEAK KW RATE	$3.974	PER ES PEAK KW

CALCULATION OF SCH 10 (PRI VOLT) RATE DESIGN

TOTAL 10 (PRI) REVENUE REQUIREMENT	$11,846,029	
DIVIDED BY 10 (PRI) ES PEAK KW	3,079,659	
= SCH 10 (PRI) ES PEAK KW PRICE	$3.847	PER ES PEAK KW

Rider T1 GS-3 EV Rates Eff. 9/1/25

Effective Date	**Proposed Rider Prices Non Demand**	**Demand**	
	$ 0.031955	$ 3.963	Total A4 Cost of Service Rates
	$ 0.014604	$ 1.950	Base Transmission Rates
9/1/2025	$ 0.017351	$ 2.013	Rider T1 GS-3 EV Rates

	Total A4 Cost of Service Rate	**Billing Determinant**	**2025 Determinant**		**2025 Revenue**	**Proposed Rider Rates**	**Proposed Revenue**
Sch GS-3	$ 6.051	On-Peak kW	21,873,787		$132,358,284		
				TOTAL	**$132,358,284**		
Sch 2 GS-2 Billing Det for GS-3 Class	**Sch GS-2 Rate as Proxy**		*Excludes Choice*				
Total Non-Demand kWh GS-3	$ 0.039511	kWh	622,424,544		$24,592,616	$ 0.031955	$19,889,544
Total Demand kW GS-3	$ 4.900	kW of Demand	28,380,214		$139,063,049	$ 3.963	$112,468,741
				TOTAL	**$163,655,665**		**$132,358,284**
				Ratio	0.808760786	**Check**	$0.00

VIRGINIA ELECTRIC AND POWER COMPANY
CALCULATION OF RIDER T1 RATES
FOR THE RATE YEAR BEGINNING SEPTEMBER 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)
	A4 Cost of Service		Included in Base Rates		Rider T1 Before Adjustment for Standby Chg. Revenue		Adjustment For Residential Class Standby Chg. Revenue		Rider T1 After Adjustment for Standby Chg. Revenue	
	kWh	kW	kWh	kW	kWh	kW	kWh		kWh	kW
Schedule 1	$0.021493		$0.00970		$0.011793		($0.000004)	(1)	$0.011789	
Schedule 1, Standby		$2.925		$1.320		$1.605				$1.605
Schedule 1G	$0.021493	$2.925	$0.00970	$1.320	$0.011793	$1.605	($0.000004)	(1)	$0.011789	$1.605
Schedule 1P	$0.021493		$0.00970		$0.011793		($0.000004)	(1)	$0.011789	
Schedule 1S	$0.021493	$2.925	$0.00970	$1.320	$0.011793	$1.605	($0.000004)	(1)	$0.011789	$1.605
Schedule 1T	$0.021493		$0.00970		$0.011793		($0.000004)	(1)	$0.011789	
Schedule 1W	$0.021493		$0.00970		$0.011793		($0.000004)	(1)	$0.011789	
Schedule DP-R	$0.021493		$0.00970		$0.011793		($0.000004)	(1)	$0.011789	
Schedule 1EV	$0.021493		$0.00970		$0.011793		($0.000004)	(1)	$0.011789	
Schedule EV	$0.021493		$0.00970		$0.011793		($0.000004)	(1)	$0.011789	
Schedule GS-1	$0.015889		$0.00582		$0.010069				$0.010069	
Schedule DP-1	$0.015889		$0.00582		$0.010069				$0.010069	
Schedule GS-2 (Non-Demand Billing)	$0.039511		$0.01476		$0.024751				$0.024751	
Schedule GS-2 (Demand Billing)		$4.900		$1.971		$2.929				$2.929
Schedule GS-2T		$5.839		$2.313		$3.526				$3.526
Schedule DP-2	$0.014068		$0.00548		$0.008588				$0.008588	
Schedule GS-3		$6.051		$2.277		$3.774				$3.774
Schedule GS-3 EV (Non-Demand Billing)	$0.031955		$0.01460		$0.017351				$0.017351	
Schedule GS-3 EV (Demand Billing)		$3.963		$1.950		$2.013				$2.013
Schedule MBR, SCR (Secondary)	$0.000297	$8.318	$0.00000	$0.000	$0.000297	$8.318			$0.000297	$8.318
Schedule GS-4 (Primary)		$6.546		$2.371		$4.175				$4.175
Schedule MBR, SCR (Primary)	$0.000297	$8.203	$0.00000	$0.000	$0.000297	$8.203			$0.000297	$8.203
Schedule GS-4 (Transmission)		$6.439		$2.310		$4.129				$4.129
Schedule MBR, SCR (Transmission)	$0.000297	$8.068	$0.00000	$0.000	$0.000297	$8.068			$0.000297	$8.068
Schedule 8 (Primary)		$6.546		$2.371		$4.175				$4.175
Schedule 8 (Transmission)		$6.439		$2.310		$4.129				$4.129
Schedule 10 (Secondary)		$3.974		$1.094		$2.880				$2.880
Schedule 10 (Primary and Transmission)		$3.847		$0.646		$3.201				$3.201
Schedule 5	$0.014068		$0.00542		$0.008648				$0.008648	
Schedule 5C	$0.018744		$0.00887		$0.009874				$0.009874	
Schedule 5P	$0.018744		$0.00887		$0.009874				$0.009874	
Schedule 6	$0.011843		$0.00482		$0.007023				$0.007023	
Schedule 6TS	$0.011843		$0.00477		$0.007073				$0.007073	
Schedule 7	$0.015889		$0.00603		$0.009859				$0.009859	
Schedule 24	$0.001961		$0.00019		$0.001771				$0.001771	
Schedule 25	$0.001961		$0.00019		$0.001771				$0.001771	
Schedule 27	$0.001961		$0.00019		$0.001771				$0.001771	
Schedule 28	$0.001961		$0.00019		$0.001771				$0.001771	
Schedule 29	$0.001961		$0.00019		$0.001771				$0.001771	

Note
1) Rider T1 Energy Charge calculation is adjusted for Standby Charge Revenue recovered through Base Transmission and Rider T1 Standby Charges.

VIRGINIA ELECTRIC AND POWER COMPANY
A 4 REVENUE BREAKDOWN, BASE RATES & RIDER T1
FOR THE RATE YEAR BEGINNING SEPTEMBER 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
										NOT USED FOR RATE DESIGN INFORMATIONAL ONLY		
Rate Schedule	Forecast kWh	Forecast kW	Proposed Gross A4 Revenue Requirement	Base kWh Rate	Base kW Rate	Revenue Recovery through Base Rates	Revenue Recovery through Base Transmission Standby Charge	Revenue Recovery through Rider T1 Standby Charge	Projected Revenue Recovery through New Rider T1 Energy Charge	Present T1 kWh Rate	Present T1 kW Rate	Projected Revenue Recovery through Present Rider T1
						(2)*(5) or (3)*(6)			(4) - (7) - (8) - (9)			(2)*(11) or (3)*(12)
All Residential	30,171,817,824		$648,491,060	$0.00970		$292,666,633	$57,548	$57,575	$355,709,304	$0.009687		$292,274,399
GS-1	4,347,345,977		$69,076,576	$0.00582		$25,301,554			$43,775,022	$0.009247		$40,199,908
GS-2, Non-Demand	622,424,544		$24,592,630	$0.01476		$9,186,986			$15,405,643	$0.022660		$14,104,140
GS-2, Demand		28,380,214	$114,460,901		$1.971	$55,937,402			$58,523,500		$3.015	$85,566,345
GS2T		5,381,910	$31,422,462		$2.313	$12,448,358			$18,974,104		$3.603	$19,391,022
GS3		21,873,787	$132,361,050		$2.277	$49,806,613			$82,554,437		$3.072	$67,196,273
GS3-EV, Non-Demand	-	-	$0	$0.01460		$0			$0	$0.000000		$0
GS3-EV, Demand	-	-	$0		$1.950	$0			$0		$0.000	$0
GS-4 (PRIM)		39,803,508	$253,144,539		$2.371	$94,374,118			$158,770,421		$3.719	$148,029,247
GS-4 (TRA)		3,838,640	$24,717,005		$2.310	$8,867,259			$15,849,746		$3.623	$13,907,394
5	23,040,769		$324,149	$0.00542		$124,881			$199,268	$0.008749		$201,584
5C	184,287,034		$3,454,199	$0.00887		$1,634,626			$1,819,573	$0.010203		$1,880,281
5P	57,636,448		$1,080,314	$0.00887		$511,235			$569,079	$0.010203		$588,065
6	3,306,902		$39,162	$0.00482		$15,939			$23,223	$0.005526		$18,274
6TS	145,066,742		$1,717,956	$0.00477		$691,968			$1,025,988	$0.005576		$808,892
7	6,729,207		$106,923	$0.00603		$40,577			$66,346	$0.009037		$60,812
10 (SEC)		6,620,191	$26,306,664		$1.094	$7,242,489			$19,064,175		$1.749	$11,578,714
10 (PRI/TRA)		3,079,659	$11,846,029		$0.646	$1,989,460			$9,856,569		$2.249	$6,926,153
24	9,232,959		$18,102	$0.00019		$1,754			$16,348	$0.000126		$1,163
25	111,355		$218	$0.00019		$21			$197	$0.000126		$14
27	62,988,560		$123,494	$0.00019		$11,968			$111,526	$0.000126		$7,937
28	22,331,846		$43,783	$0.00019		$4,243			$39,540	$0.000126		$2,814
29	4,345,190		$8,519	$0.00019		$826			$7,693	$0.000126		$547
Total			$1,343,335,735			$560,858,910	$57,548	$57,575	$782,361,702			$702,743,978

Total Base Transmission Revenue Including Base Transmission Standby Charges $560,916,458

Total Rider T1 Revenue Including Rider T1 Standby Charges $782,419,278

RIDER T1

TRANSMISSION

The following Virginia Electric and Power Company filed Bundled Rate Schedules and special contracts approved by the State Corporation Commission pursuant to Virginia Code § 56-235.2 shall be increased by the applicable cents per kilowatt-hour and/or dollars per kilowatt charge.

Rate Schedules	Cents per Electricity Supply kWh Charge	Dollars per kW Demand Charge
Schedules 1, 1G, 1P, 1S, 1T, 1W, DP-R, 1EV, EV	1.1789¢/kWh	$1.605/kW[1]
Schedules GS-1, DP-1	1.0069¢/kWh	
Schedule GS-2 (Non-Demand Billing)	2.4751¢/kWh	
Schedule GS-2 (Demand Billing)		$2.929/kW[2]
Schedule GS-2T		$3.526/kW[3]
Schedule DP-2	0.8588¢/kWh	
Schedule GS-3 (Secondary)		$3.774/kW[3]
Schedule GS-3 EV (Non-Demand Billing)	1.7351¢/kWh	
Schedule GS-3 EV (Demand Billing)		$2.013/kW[2]
Schedules MBR, SCR (Secondary)	0.0297¢/kWh[6]	$8.318/kW[6]
Schedule GS-4 (Primary)		$4.175/kW[3]
Schedules MBR, SCR (Primary)	0.0297¢/kWh[6]	$8.203/kW[6]
Schedule GS-4 (Transmission)		$4.129/kW[3]
Schedules MBR, SCR (Transmission)	0.0297¢/kWh[6]	$8.068/kW[6]
Schedule 8 (Primary)		$4.175/kW[4]
Schedule 8 (Transmission)		$4.129/kW[4]
Schedule 10 (Secondary)		$2.880/kW[5]
Schedule 10 (Primary and Transmission)		$3.201/kW[5]
Schedule 5	0.8648¢/kWh	
Schedule 5C	0.9874¢/kWh	
Schedule 5P	0.9874¢/kWh	
Schedule 6	0.7023¢/kWh	
Schedule 6TS	0.7073¢/kWh	
Schedule 7	0.9859¢/kWh	
Schedules 24, 25, 27, 28, 29	0.1771¢/kWh	

[1]Applied to kW of Demand only for Schedules 1, 1G, and 1S net-metering applications where generation is sized above 15 kW. Such installations will pay the Rider T1 energy charge or the Rider T1 demand charge, whichever is greater.
[2]Applied to kW of Demand
[3]Applied to kW of On-peak Electricity Supply Demand
[4]Applied to kW of Contract Supplementary - Standby Demand
[5]Applied to kW of Electricity Supply Peak Demand
[6]Applied to Customer's NSPL (12CP Based) kW Demand and kWh Energy

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - RESIDENTIAL - SCHEDULE 1

SUMMER MONTHS

	EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
KWH	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
500	$39.79	$28.96	$15.83	$84.58	$39.79	$30.01	$15.83	$85.63	$1.05	1.2%
750	$55.90	$43.47	$23.75	$123.12	$55.90	$45.04	$23.75	$124.69	$1.57	1.3%
1,000	$73.53	$57.96	$31.66	$163.15	$73.53	$60.06	$31.66	$165.25	$2.10	1.3%
1,500	$109.60	$86.91	$47.50	$244.01	$109.60	$90.06	$47.50	$247.16	$3.15	1.3%
2,000	$145.65	$115.90	$63.33	$324.88	$145.65	$120.11	$63.33	$329.09	$4.21	1.3%
2,500	$181.70	$144.87	$79.16	$405.73	$181.70	$150.12	$79.16	$410.98	$5.25	1.3%
3,000	$217.77	$173.85	$94.99	$486.61	$217.77	$180.16	$94.99	$492.92	$6.31	1.3%
5,000	$361.99	$289.78	$158.32	$810.09	$361.99	$300.29	$158.32	$820.60	$10.51	1.3%

BASE MONTHS

	EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
KWH	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
500	$39.28	$28.96	$15.83	$84.07	$39.28	$30.01	$15.83	$85.12	$1.05	1.2%
750	$55.12	$43.47	$23.75	$122.34	$55.12	$45.04	$23.75	$123.91	$1.57	1.3%
1,000	$68.85	$57.96	$31.66	$158.47	$68.85	$60.06	$31.66	$160.57	$2.10	1.3%
1,500	$95.27	$86.91	$47.50	$229.68	$95.27	$90.06	$47.50	$232.83	$3.15	1.4%
2,000	$121.69	$115.90	$63.33	$300.92	$121.69	$120.11	$63.33	$305.13	$4.21	1.4%
2,500	$148.10	$144.87	$79.16	$372.13	$148.10	$150.12	$79.16	$377.38	$5.25	1.4%
3,000	$174.53	$173.85	$94.99	$443.37	$174.53	$180.16	$94.99	$449.68	$6.31	1.4%
5,000	$280.20	$289.78	$158.32	$728.30	$280.20	$300.29	$158.32	$738.81	$10.51	1.4%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - SCHEDULE GS-1

SUMMER MONTHS

				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
BILL KW	KWH	PHASE	LOAD FACTOR	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
5	500	1	14%	$38.84	$23.62	$15.67	$78.13	$38.84	$24.03	$15.67	$78.54	$0.41	0.5%
	500	3	14%	$43.50	$23.62	$15.67	$82.79	$43.50	$24.03	$15.67	$83.20	$0.41	0.5%
	1,000	1	28%	$64.28	$47.30	$31.35	$142.93	$64.28	$48.12	$31.35	$143.75	$0.82	0.6%
	1,000	3	28%	$68.94	$47.30	$31.35	$147.59	$68.94	$48.12	$31.35	$148.41	$0.82	0.6%
	1,500	1	42%	$90.51	$70.91	$47.02	$208.44	$90.51	$72.14	$47.02	$209.67	$1.23	0.6%
	1,500	3	42%	$95.17	$70.91	$47.02	$213.10	$95.17	$72.14	$47.02	$214.33	$1.23	0.6%
	2,000	1	56%	$119.89	$94.58	$62.69	$277.16	$119.89	$96.23	$62.69	$278.81	$1.65	0.6%
	2,000	3	56%	$124.55	$94.58	$62.69	$281.82	$124.55	$96.23	$62.69	$283.47	$1.65	0.6%
15	1,500	1	14%	$90.51	$70.91	$47.02	$208.44	$90.51	$72.14	$47.02	$209.67	$1.23	0.6%
	1,500	3	14%	$95.17	$70.91	$47.02	$213.10	$95.17	$72.14	$47.02	$214.33	$1.23	0.6%
	3,000	1	28%	$178.64	$141.85	$94.04	$414.53	$178.64	$144.32	$94.04	$417.00	$2.47	0.6%
	3,000	3	28%	$183.30	$141.85	$94.04	$419.19	$183.30	$144.32	$94.04	$421.66	$2.47	0.6%
	4,500	1	42%	$266.77	$212.79	$141.05	$620.61	$266.77	$216.49	$141.05	$624.31	$3.70	0.6%
	4,500	3	42%	$271.43	$212.79	$141.05	$625.27	$271.43	$216.49	$141.05	$628.97	$3.70	0.6%
	6,000	1	56%	$354.89	$283.72	$188.07	$826.68	$354.89	$288.65	$188.07	$831.61	$4.93	0.6%
	6,000	3	56%	$359.55	$283.72	$188.07	$831.34	$359.55	$288.65	$188.07	$836.27	$4.93	0.6%
25	2,500	1	14%	$149.26	$118.21	$78.36	$345.83	$149.26	$120.26	$78.36	$347.88	$2.05	0.6%
	2,500	3	14%	$153.92	$118.21	$78.36	$350.49	$153.92	$120.26	$78.36	$352.54	$2.05	0.6%
	5,000	1	28%	$296.14	$236.48	$156.73	$689.35	$296.14	$240.59	$156.73	$693.46	$4.11	0.6%
	5,000	3	28%	$300.80	$236.48	$156.73	$694.01	$300.80	$240.59	$156.73	$698.12	$4.11	0.6%
	7,500	1	42%	$443.02	$354.65	$235.09	$1,032.76	$443.02	$360.82	$235.09	$1,038.93	$6.17	0.6%
	7,500	3	42%	$447.68	$354.65	$235.09	$1,037.42	$447.68	$360.82	$235.09	$1,043.59	$6.17	0.6%
	10,000	1	56%	$589.90	$472.86	$313.45	$1,376.21	$589.90	$481.08	$313.45	$1,384.43	$8.22	0.6%
	10,000	3	56%	$594.56	$472.86	$313.45	$1,380.87	$594.56	$481.08	$313.45	$1,389.09	$8.22	0.6%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - SCHEDULE GS-1

BASE MONTHS

				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
BILL KW	KWH	PHASE	LOAD FACTOR	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
5	500	1	14%	$38.84	$23.62	$15.67	$78.13	$38.84	$24.03	$15.67	$78.54	$0.41	0.5%
	500	3	14%	$43.50	$23.62	$15.67	$82.79	$43.50	$24.03	$15.67	$83.20	$0.41	0.5%
	1,000	1	28%	$64.28	$47.30	$31.35	$142.93	$64.28	$48.12	$31.35	$143.75	$0.82	0.6%
	1,000	3	28%	$68.94	$47.30	$31.35	$147.59	$68.94	$48.12	$31.35	$148.41	$0.82	0.6%
	1,500	1	42%	$88.71	$70.91	$47.02	$206.64	$88.71	$72.14	$47.02	$207.87	$1.23	0.6%
	1,500	3	42%	$93.37	$70.91	$47.02	$211.30	$93.37	$72.14	$47.02	$212.53	$1.23	0.6%
	2,000	1	56%	$109.05	$94.58	$62.69	$266.32	$109.05	$96.23	$62.69	$267.97	$1.65	0.6%
	2,000	3	56%	$113.71	$94.58	$62.69	$270.98	$113.71	$96.23	$62.69	$272.63	$1.65	0.6%
15	1,500	1	14%	$88.71	$70.91	$47.02	$206.64	$88.71	$72.14	$47.02	$207.87	$1.23	0.6%
	1,500	3	14%	$93.37	$70.91	$47.02	$211.30	$93.37	$72.14	$47.02	$212.53	$1.23	0.6%
	3,000	1	28%	$149.74	$141.85	$94.04	$385.63	$149.74	$144.32	$94.04	$388.10	$2.47	0.6%
	3,000	3	28%	$154.40	$141.85	$94.04	$390.29	$154.40	$144.32	$94.04	$392.76	$2.47	0.6%
	4,500	1	42%	$210.77	$212.79	$141.05	$564.61	$210.77	$216.49	$141.05	$568.31	$3.70	0.7%
	4,500	3	42%	$215.43	$212.79	$141.05	$569.27	$215.43	$216.49	$141.05	$572.97	$3.70	0.6%
	6,000	1	56%	$271.80	$283.72	$188.07	$743.59	$271.80	$288.65	$188.07	$748.52	$4.93	0.7%
	6,000	3	56%	$276.46	$283.72	$188.07	$748.25	$276.46	$288.65	$188.07	$753.18	$4.93	0.7%
25	2,500	1	14%	$129.39	$118.21	$78.36	$325.96	$129.39	$120.26	$78.36	$328.01	$2.05	0.6%
	2,500	3	14%	$134.05	$118.21	$78.36	$330.62	$134.05	$120.26	$78.36	$332.67	$2.05	0.6%
	5,000	1	28%	$231.11	$236.48	$156.73	$624.32	$231.11	$240.59	$156.73	$628.43	$4.11	0.7%
	5,000	3	28%	$235.77	$236.48	$156.73	$628.98	$235.77	$240.59	$156.73	$633.09	$4.11	0.7%
	7,500	1	42%	$332.83	$354.65	$235.09	$922.57	$332.83	$360.82	$235.09	$928.74	$6.17	0.7%
	7,500	3	42%	$337.49	$354.65	$235.09	$927.23	$337.49	$360.82	$235.09	$933.40	$6.17	0.7%
	10,000	1	56%	$434.55	$472.86	$313.45	$1,220.86	$434.55	$481.08	$313.45	$1,229.08	$8.22	0.7%
	10,000	3	56%	$439.21	$472.86	$313.45	$1,225.52	$439.21	$481.08	$313.45	$1,233.74	$8.22	0.7%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - SCHEDULE GS-2

SUMMER MONTHS

			EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025 9/1/2025					
BILL KW	KWH	LOAD FACTOR	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
30	4,500	21%	$354.83	$273.44	$141.12	$769.39	$354.83	$282.85	$141.12	$778.80	$9.41	1.2%
	9,000	42%	$508.27	$438.89	$282.23	$1,229.39	$508.27	$436.31	$282.23	$1,226.81	($2.58)	-0.2%
	15,000	69%	$549.68	$560.87	$463.44	$1,573.99	$549.68	$558.29	$463.44	$1,571.41	($2.58)	-0.2%
50	7,500	21%	$572.79	$455.73	$235.19	$1,263.71	$572.79	$471.41	$235.19	$1,279.39	$15.68	1.2%
	15,000	42%	$828.52	$731.50	$470.39	$2,030.41	$828.52	$727.20	$470.39	$2,026.11	($4.30)	-0.2%
	25,000	69%	$897.54	$934.77	$772.40	$2,604.71	$897.54	$930.47	$772.40	$2,600.41	($4.30)	-0.2%
100	15,000	21%	$1,117.69	$911.52	$470.39	$2,499.60	$1,117.69	$942.89	$470.39	$2,530.97	$31.37	1.3%
	30,000	42%	$1,629.16	$1,462.92	$940.77	$4,032.85	$1,629.16	$1,454.32	$940.77	$4,024.25	($8.60)	-0.2%
	50,000	69%	$1,767.20	$1,869.50	$1,544.80	$5,181.50	$1,767.20	$1,860.90	$1,544.80	$5,172.90	($8.60)	-0.2%
150	22,500	21%	$1,662.58	$1,367.24	$705.58	$3,735.40	$1,662.58	$1,414.29	$705.58	$3,782.45	$47.05	1.3%
	45,000	42%	$2,429.79	$2,194.42	$1,411.16	$6,035.37	$2,429.79	$2,181.52	$1,411.16	$6,022.47	($12.90)	-0.2%
	75,000	69%	$2,636.84	$2,804.27	$2,317.20	$7,758.31	$2,636.84	$2,791.37	$2,317.20	$7,745.41	($12.90)	-0.2%
250	37,500	21%	$2,752.38	$2,278.68	$1,175.96	$6,207.02	$2,752.38	$2,357.09	$1,175.96	$6,285.43	$78.41	1.3%
	75,000	42%	$4,031.05	$3,657.34	$2,351.93	$10,040.32	$4,031.05	$3,635.84	$2,351.93	$10,018.82	($21.50)	-0.2%
	125,000	69%	$4,376.14	$4,673.77	$3,862.00	$12,911.91	$4,376.14	$4,652.27	$3,862.00	$12,890.41	($21.50)	-0.2%
450	67,500	21%	$4,931.97	$4,101.63	$2,116.73	$11,150.33	$4,931.97	$4,242.77	$2,116.73	$11,291.47	$141.14	1.3%
	135,000	42%	$7,233.58	$6,583.18	$4,233.47	$18,050.23	$7,233.58	$6,544.48	$4,233.47	$18,011.53	($38.70)	-0.2%
	225,000	69%	$7,854.74	$8,412.77	$6,951.60	$23,219.11	$7,854.74	$8,374.07	$6,951.60	$23,180.41	($38.70)	-0.2%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - SCHEDULE GS-2

BASE MONTHS

			EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
BILL KW	KWH	LOAD FACTOR	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
30	4,500	21%	$333.89	$273.44	$141.12	$748.45	$333.89	$282.85	$141.12	$757.86	$9.41	1.3%
	9,000	42%	$475.72	$439.32	$282.23	$1,197.27	$475.72	$436.74	$282.23	$1,194.69	($2.58)	-0.2%
	15,000	69%	$517.13	$560.87	$463.44	$1,541.44	$517.13	$558.29	$463.44	$1,538.86	($2.58)	-0.2%
50	7,500	21%	$537.89	$455.73	$235.19	$1,228.81	$537.89	$471.41	$235.19	$1,244.49	$15.68	1.3%
	15,000	42%	$774.27	$732.22	$470.39	$1,976.88	$774.27	$727.92	$470.39	$1,972.58	($4.30)	-0.2%
	25,000	69%	$843.29	$934.77	$772.40	$2,550.46	$843.29	$930.47	$772.40	$2,546.16	($4.30)	-0.2%
100	15,000	21%	$1,047.89	$911.52	$470.39	$2,429.80	$1,047.89	$942.89	$470.39	$2,461.17	$31.37	1.3%
	30,000	42%	$1,520.66	$1,464.37	$940.77	$3,925.80	$1,520.66	$1,455.77	$940.77	$3,917.20	($8.60)	-0.2%
	50,000	69%	$1,658.70	$1,869.50	$1,544.80	$5,073.00	$1,658.70	$1,860.90	$1,544.80	$5,064.40	($8.60)	-0.2%
150	22,500	21%	$1,557.89	$1,367.24	$705.58	$3,630.71	$1,557.89	$1,414.29	$705.58	$3,677.76	$47.05	1.3%
	45,000	42%	$2,267.04	$2,196.59	$1,411.16	$5,874.79	$2,267.04	$2,183.69	$1,411.16	$5,861.89	($12.90)	-0.2%
	75,000	69%	$2,474.09	$2,804.27	$2,317.20	$7,595.56	$2,474.09	$2,791.37	$2,317.20	$7,582.66	($12.90)	-0.2%
250	37,500	21%	$2,577.89	$2,278.68	$1,175.96	$6,032.53	$2,577.89	$2,357.09	$1,175.96	$6,110.94	$78.41	1.3%
	75,000	42%	$3,759.80	$3,660.96	$2,351.93	$9,772.69	$3,759.80	$3,639.46	$2,351.93	$9,751.19	($21.50)	-0.2%
	125,000	69%	$4,104.89	$4,673.77	$3,862.00	$12,640.66	$4,104.89	$4,652.27	$3,862.00	$12,619.16	($21.50)	-0.2%
450	67,500	21%	$4,617.89	$4,101.63	$2,116.73	$10,836.25	$4,617.89	$4,242.77	$2,116.73	$10,977.39	$141.14	1.3%
	135,000	42%	$6,745.33	$6,589.70	$4,233.47	$17,568.50	$6,745.33	$6,551.00	$4,233.47	$17,529.80	($38.70)	-0.2%
	225,000	69%	$7,366.49	$8,412.77	$6,951.60	$22,730.86	$7,366.49	$8,374.07	$6,951.60	$22,692.16	($38.70)	-0.2%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - SCHEDULE GS-3
CALCULATED FOR 40% AND 60% ON-PEAK KWH USAGE

				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
BILL KW	LOAD FACTOR	ON-PEAK KWH	OFF-PEAK KWH	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
500	28%	40,000	60,000	$7,060.39	$6,225.40	$3,246.50	$16,532.29	$7,060.39	$6,576.40	$3,246.50	$16,883.29	$351.00	2.1%
	28%	60,000	40,000	$7,085.73	$6,225.40	$3,246.50	$16,557.63	$7,085.73	$6,576.40	$3,246.50	$16,908.63	$351.00	2.1%
	49%	70,000	105,000	$7,300.38	$7,210.84	$5,472.50	$19,983.72	$7,300.38	$7,561.84	$5,472.50	$20,334.72	$351.00	1.8%
	49%	105,000	70,000	$7,344.72	$7,210.84	$5,472.50	$20,028.06	$7,344.72	$7,561.84	$5,472.50	$20,379.06	$351.00	1.8%
	69%	100,000	150,000	$7,540.36	$8,196.25	$7,698.50	$23,435.11	$7,540.36	$8,547.25	$7,698.50	$23,786.11	$351.00	1.5%
	69%	150,000	100,000	$7,603.71	$8,196.25	$7,698.50	$23,498.46	$7,603.71	$8,547.25	$7,698.50	$23,849.46	$351.00	1.5%
1,000	28%	80,000	120,000	$13,978.20	$12,450.80	$6,493.00	$32,922.00	$13,978.20	$13,152.80	$6,493.00	$33,624.00	$702.00	2.1%
	28%	120,000	80,000	$14,028.88	$12,450.80	$6,493.00	$32,972.68	$14,028.88	$13,152.80	$6,493.00	$33,674.68	$702.00	2.1%
	49%	140,000	210,000	$14,458.17	$14,421.65	$10,945.00	$39,824.82	$14,458.17	$15,123.65	$10,945.00	$40,526.82	$702.00	1.8%
	49%	210,000	140,000	$14,546.86	$14,421.65	$10,945.00	$39,913.51	$14,546.86	$15,123.65	$10,945.00	$40,615.51	$702.00	1.8%
	69%	200,000	300,000	$14,938.14	$16,392.50	$15,397.00	$46,727.64	$14,938.14	$17,094.50	$15,397.00	$47,429.64	$702.00	1.5%
	69%	300,000	200,000	$15,064.84	$16,392.50	$15,397.00	$46,854.34	$15,064.84	$17,094.50	$15,397.00	$47,556.34	$702.00	1.5%
5,000	28%	400,000	600,000	$69,320.50	$62,254.00	$32,465.00	$164,039.50	$69,320.50	$65,764.00	$32,465.00	$167,549.50	$3,510.00	2.1%
	28%	600,000	400,000	$69,573.90	$62,254.00	$32,465.00	$164,292.90	$69,573.90	$65,764.00	$32,465.00	$167,802.90	$3,510.00	2.1%
	49%	700,000	1,050,000	$71,720.35	$72,108.25	$54,725.00	$198,553.60	$71,720.35	$75,618.25	$54,725.00	$202,063.60	$3,510.00	1.8%
	49%	1,050,000	700,000	$72,163.80	$72,108.25	$54,725.00	$198,997.05	$72,163.80	$75,618.25	$54,725.00	$202,507.05	$3,510.00	1.8%
	69%	1,000,000	1,500,000	$74,120.20	$81,962.50	$76,985.00	$233,067.70	$74,120.20	$85,472.50	$76,985.00	$236,577.70	$3,510.00	1.5%
	69%	1,500,000	1,000,000	$74,753.70	$81,962.50	$76,985.00	$233,701.20	$74,753.70	$85,472.50	$76,985.00	$237,211.20	$3,510.00	1.5%
10,000	28%	800,000	1,200,000	$138,498.43	$124,508.00	$64,930.00	$327,936.43	$138,498.43	$131,528.00	$64,930.00	$334,956.43	$7,020.00	2.1%
	28%	1,200,000	800,000	$139,005.23	$124,508.00	$64,930.00	$328,443.23	$139,005.23	$131,528.00	$64,930.00	$335,463.23	$7,020.00	2.1%
	49%	1,400,000	2,100,000	$143,298.13	$144,216.50	$109,450.00	$396,964.63	$143,298.13	$151,236.50	$109,450.00	$403,984.63	$7,020.00	1.8%
	49%	2,100,000	1,400,000	$144,185.03	$144,216.50	$109,450.00	$397,851.53	$144,185.03	$151,236.50	$109,450.00	$404,871.53	$7,020.00	1.8%
	69%	2,000,000	3,000,000	$148,097.83	$163,925.00	$153,970.00	$465,992.83	$148,097.83	$170,945.00	$153,970.00	$473,012.83	$7,020.00	1.5%
	69%	3,000,000	2,000,000	$149,364.83	$163,925.00	$153,970.00	$467,259.83	$149,364.83	$170,945.00	$153,970.00	$474,279.83	$7,020.00	1.5%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - SCHEDULE GS-4
CALCULATED FOR 40% AND 60% ON-PEAK KWH USAGE
PRIMARY SERVICE

				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
BILL KW	LOAD FACTOR	ON-PEAK KWH	OFF-PEAK KWH	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
500	28%	40,000	60,000	$6,973.72	$6,071.20	$3,251.50	$16,296.42	$6,973.72	$6,299.20	$3,251.50	$16,524.42	$228.00	1.4%
	28%	60,000	40,000	$6,999.06	$6,071.20	$3,251.50	$16,321.76	$6,999.06	$6,299.20	$3,251.50	$16,549.76	$228.00	1.4%
	56%	80,000	120,000	$7,294.40	$7,366.40	$6,219.50	$20,880.30	$7,294.40	$7,594.40	$6,219.50	$21,108.30	$228.00	1.1%
	56%	120,000	80,000	$7,345.08	$7,366.40	$6,219.50	$20,930.98	$7,345.08	$7,594.40	$6,219.50	$21,158.98	$228.00	1.1%
	83%	120,000	180,000	$7,615.08	$8,661.60	$9,187.50	$25,464.18	$7,615.08	$8,889.60	$9,187.50	$25,692.18	$228.00	0.9%
	83%	150,000	150,000 &	$7,653.09	$8,661.60	$9,187.50	$25,502.19	$7,653.09	$8,889.60	$9,187.50	$25,730.19	$228.00	0.9%
5,000	28%	400,000	600,000	$67,944.98	$60,712.00	$32,515.00	$161,171.98	$67,944.98	$62,992.00	$32,515.00	$163,451.98	$2,280.00	1.4%
	28%	600,000	400,000	$68,198.38	$60,712.00	$32,515.00	$161,425.38	$68,198.38	$62,992.00	$32,515.00	$163,705.38	$2,280.00	1.4%
	56%	800,000	1,200,000	$71,151.78	$73,664.00	$62,195.00	$207,010.78	$71,151.78	$75,944.00	$62,195.00	$209,290.78	$2,280.00	1.1%
	56%	1,200,000	800,000	$71,658.58	$73,664.00	$62,195.00	$207,517.58	$71,658.58	$75,944.00	$62,195.00	$209,797.58	$2,280.00	1.1%
	83%	1,200,000	1,800,000	$74,358.58	$86,616.00	$91,875.00	$252,849.58	$74,358.58	$88,896.00	$91,875.00	$255,129.58	$2,280.00	0.9%
	83%	1,500,000	1,500,000 &	$74,738.68	$86,616.00	$91,875.00	$253,229.68	$74,738.68	$88,896.00	$91,875.00	$255,509.68	$2,280.00	0.9%
10,000	28%	800,000	1,200,000	$133,830.86	$121,424.00	$65,030.00	$320,284.86	$133,830.86	$125,984.00	$65,030.00	$324,844.86	$4,560.00	1.4%
	28%	1,200,000	800,000	$134,337.66	$121,424.00	$65,030.00	$320,791.66	$134,337.66	$125,984.00	$65,030.00	$325,351.66	$4,560.00	1.4%
	56%	1,600,000	2,400,000	$140,244.46	$147,328.00	$124,390.00	$411,962.46	$140,244.46	$151,888.00	$124,390.00	$416,522.46	$4,560.00	1.1%
	56%	2,400,000	1,600,000	$141,258.06	$147,328.00	$124,390.00	$412,976.06	$141,258.06	$151,888.00	$124,390.00	$417,536.06	$4,560.00	1.1%
	83%	2,400,000	3,600,000	$146,658.06	$173,232.00	$183,750.00	$503,640.06	$146,658.06	$177,792.00	$183,750.00	$508,200.06	$4,560.00	0.9%
	83%	3,000,000	3,000,000 &	$147,418.26	$173,232.00	$183,750.00	$504,400.26	$147,418.26	$177,792.00	$183,750.00	$508,960.26	$4,560.00	0.9%
30,000	28%	2,400,000	3,600,000	$397,374.12	$364,272.00	$195,090.00	$956,736.12	$397,374.12	$377,952.00	$195,090.00	$970,416.12	$13,680.00	1.4%
	28%	3,600,000	2,400,000	$398,894.52	$364,272.00	$195,090.00	$958,256.52	$398,894.52	$377,952.00	$195,090.00	$971,936.52	$13,680.00	1.4%
	56%	4,800,000	7,200,000	$416,614.92	$441,984.00	$373,170.00	$1,231,768.92	$416,614.92	$455,664.00	$373,170.00	$1,245,448.92	$13,680.00	1.1%
	56%	7,200,000	4,800,000	$419,655.72	$441,984.00	$373,170.00	$1,234,809.72	$419,655.72	$455,664.00	$373,170.00	$1,248,489.72	$13,680.00	1.1%
	83%	7,200,000	10,800,000	$435,855.72	$519,696.00	$551,250.00	$1,506,801.72	$435,855.72	$533,376.00	$551,250.00	$1,520,481.72	$13,680.00	0.9%
	83%	9,000,000	9,000,000 &	$438,136.32	$519,696.00	$551,250.00	$1,509,082.32	$438,136.32	$533,376.00	$551,250.00	$1,522,762.32	$13,680.00	0.9%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*
& On-peak kWh set at maximum level that could be consumed in a base month assuming a 100% on-peak load factor for 30 days.

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - SCHEDULE GS-4
CALCULATED FOR 40% AND 60% ON-PEAK KWH USAGE
TRANSMISSION SERVICE

				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
BILL KW	LOAD FACTOR	ON-PEAK KWH	OFF-PEAK KWH	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
500	28%	40,000	60,000	$6,083.72	$5,830.20	$3,247.00	$15,160.92	$6,083.72	$6,083.20	$3,247.00	$15,413.92	$253.00	1.7%
	28%	60,000	40,000	$6,109.06	$5,830.20	$3,247.00	$15,186.26	$6,109.06	$6,083.20	$3,247.00	$15,439.26	$253.00	1.7%
	56%	80,000	120,000	$6,404.40	$7,125.40	$6,215.00	$19,744.80	$6,404.40	$7,378.40	$6,215.00	$19,997.80	$253.00	1.3%
	56%	120,000	80,000	$6,455.08	$7,125.40	$6,215.00	$19,795.48	$6,455.08	$7,378.40	$6,215.00	$20,048.48	$253.00	1.3%
	83%	120,000	180,000	$6,725.08	$8,420.60	$9,183.00	$24,328.68	$6,725.08	$8,673.60	$9,183.00	$24,581.68	$253.00	1.0%
	83%	150,000	150,000 &	$6,763.09	$8,420.60	$9,183.00	$24,366.69	$6,763.09	$8,673.60	$9,183.00	$24,619.69	$253.00	1.0%
5,000	28%	400,000	600,000	$59,044.98	$58,302.00	$32,470.00	$149,816.98	$59,044.98	$60,832.00	$32,470.00	$152,346.98	$2,530.00	1.7%
	28%	600,000	400,000	$59,298.38	$58,302.00	$32,470.00	$150,070.38	$59,298.38	$60,832.00	$32,470.00	$152,600.38	$2,530.00	1.7%
	56%	800,000	1,200,000	$62,251.78	$71,254.00	$62,150.00	$195,655.78	$62,251.78	$73,784.00	$62,150.00	$198,185.78	$2,530.00	1.3%
	56%	1,200,000	800,000	$62,758.58	$71,254.00	$62,150.00	$196,162.58	$62,758.58	$73,784.00	$62,150.00	$198,692.58	$2,530.00	1.3%
	83%	1,200,000	1,800,000	$65,458.58	$84,206.00	$91,830.00	$241,494.58	$65,458.58	$86,736.00	$91,830.00	$244,024.58	$2,530.00	1.0%
	83%	1,500,000	1,500,000 &	$65,838.68	$84,206.00	$91,830.00	$241,874.68	$65,838.68	$86,736.00	$91,830.00	$244,404.68	$2,530.00	1.0%
10,000	28%	800,000	1,200,000	$117,890.86	$116,604.00	$64,940.00	$299,434.86	$117,890.86	$121,664.00	$64,940.00	$304,494.86	$5,060.00	1.7%
	28%	1,200,000	800,000	$118,397.66	$116,604.00	$64,940.00	$299,941.66	$118,397.66	$121,664.00	$64,940.00	$305,001.66	$5,060.00	1.7%
	56%	1,600,000	2,400,000	$124,304.46	$142,508.00	$124,300.00	$391,112.46	$124,304.46	$147,568.00	$124,300.00	$396,172.46	$5,060.00	1.3%
	56%	2,400,000	1,600,000	$125,318.06	$142,508.00	$124,300.00	$392,126.06	$125,318.06	$147,568.00	$124,300.00	$397,186.06	$5,060.00	1.3%
	83%	2,400,000	3,600,000	$130,718.06	$168,412.00	$183,660.00	$482,790.06	$130,718.06	$173,472.00	$183,660.00	$487,850.06	$5,060.00	1.0%
	83%	3,000,000	3,000,000 &	$131,478.26	$168,412.00	$183,660.00	$483,550.26	$131,478.26	$173,472.00	$183,660.00	$488,610.26	$5,060.00	1.0%
30,000	28%	2,400,000	3,600,000	$353,274.12	$349,812.00	$194,820.00	$897,906.12	$353,274.12	$364,992.00	$194,820.00	$913,086.12	$15,180.00	1.7%
	28%	3,600,000	2,400,000	$354,794.52	$349,812.00	$194,820.00	$899,426.52	$354,794.52	$364,992.00	$194,820.00	$914,606.52	$15,180.00	1.7%
	56%	4,800,000	7,200,000	$372,514.92	$427,524.00	$372,900.00	$1,172,938.92	$372,514.92	$442,704.00	$372,900.00	$1,188,118.92	$15,180.00	1.3%
	56%	7,200,000	4,800,000	$375,555.72	$427,524.00	$372,900.00	$1,175,979.72	$375,555.72	$442,704.00	$372,900.00	$1,191,159.72	$15,180.00	1.3%
	83%	7,200,000	10,800,000	$391,755.72	$505,236.00	$550,980.00	$1,447,971.72	$391,755.72	$520,416.00	$550,980.00	$1,463,151.72	$15,180.00	1.0%
	83%	9,000,000	9,000,000 &	$394,036.32	$505,236.00	$550,980.00	$1,450,252.32	$394,036.32	$520,416.00	$550,980.00	$1,465,432.32	$15,180.00	1.0%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*
& On-peak kWh set at maximum level that could be consumed in a base month assuming a 100% on-peak load factor for 30 days.

VIRGINIA ELECTRIC AND POWER COMPANY
TYPICAL BILLS - CHURCH AND SYNAGOGUE - SCHEDULE 5C

SUMMER MONTHS

	EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
KWH	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
1,500	$110.24	$87.59	$47.80	$245.63	$110.24	$87.10	$47.80	$245.14	($0.49)	-0.2%
3,000	$208.97	$175.21	$95.60	$479.78	$208.97	$174.22	$95.60	$478.79	($0.99)	-0.2%
5,000	$334.71	$292.04	$159.33	$786.08	$334.71	$290.39	$159.33	$784.43	($1.65)	-0.2%
7,500	$491.88	$438.01	$238.99	$1,168.88	$491.88	$435.55	$238.99	$1,166.42	($2.46)	-0.2%
10,000	$649.05	$584.01	$318.65	$1,551.71	$649.05	$580.72	$318.65	$1,548.42	($3.29)	-0.2%
15,000	$963.39	$876.05	$477.98	$2,317.42	$963.39	$871.11	$477.98	$2,312.48	($4.94)	-0.2%

BASE MONTHS

	EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025				EFFECTIVE FOR USAGE ON AND AFTER 9/1/2025					
KWH	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES##	FUEL RIDER A*	TOTAL BILL	BASIC RATE #	OTHER APPLICABLE RIDERS, FEES AND CHARGES###	FUEL RIDER A*	TOTAL BILL	DIFFERENCE	PERCENT DIFFERENCE
1,500	$110.24	$87.59	$47.80	$245.63	$110.24	$87.10	$47.80	$245.14	($0.49)	-0.2%
3,000	$208.97	$175.21	$95.60	$479.78	$208.97	$174.22	$95.60	$478.79	($0.99)	-0.2%
5,000	$326.25	$292.04	$159.33	$777.62	$326.25	$290.39	$159.33	$775.97	($1.65)	-0.2%
7,500	$472.85	$438.01	$238.99	$1,149.85	$472.85	$435.55	$238.99	$1,147.39	($2.46)	-0.2%
10,000	$619.44	$584.01	$318.65	$1,522.10	$619.44	$580.72	$318.65	$1,518.81	($3.29)	-0.2%
15,000	$912.64	$876.05	$477.98	$2,266.67	$912.64	$871.11	$477.98	$2,261.73	($4.94)	-0.2%

 # Basic rate includes base distribution, generation, and base transmission rates.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 without proposed Rider T1 change.
Reflects current and pending applicable non-base rate riders, proposed deferred fuel cost charge (Securitization), and PIPP universal service fee to be effective September 1, 2025 with proposed Rider T1 change.
** Reflects total proposed fuel level of $0.029680 per kWh.*
*** The rates used in this schedule are based on the revenue requirements as filed in each case.*

DOMINION ENERGY VIRGINIA
1,000 KWH SEASONALLY WEIGHTED RESIDENTIAL BILL
RATE SCHEDULE 1

BILL COMPONENTS	September 2025
DISTRIBUTION - BASE	$ 32.84
GENERATION - BASE	$ 27.87
TRANSMISSION	$ 21.49
FUEL	$ 31.66
VIRGINIA CLEAN ECONOMY ACT	$ 22.58
DISTRIBUTION A6	$ 6.79
GENERATION A6	$ 11.33
ENVIRONMENTAL A5	$ 2.53
DSM/EE	$ 1.59
PIPP	$ -
DEFERRED FUEL COST CHARGE	$ 3.45
TOTAL BILL	**$ 162.13**

	RATES	RATES	KWH 1,000	KWH 1,000	
BILL COMPONENTS	**SUMMER**	**NON-SUMMER**	**SUMMER**	**NON-SUMMER**	**WEIGHTED**
Basic Customer Charge	$7.58	$7.58	$ 7.58	$ 7.58	$ 7.58
Distribution 800 kWh	$ 0.026656	$ 0.026656	$ 21.32	$ 21.32	$ 21.32
Distribution Over 800 kWh	$ 0.019708	$ 0.019708	$ 3.94	$ 3.94	$ 3.94
Electricity Supply Service 800 kWh	$ 0.028063	$ 0.027031	$ 22.45	$ 21.62	$ 21.90
Electricity Supply Service Over 800 kWh	$ 0.042708	$ 0.023430	$ 8.54	$ 4.69	$ 5.97
Base Transmission	$ 0.009700	$ 0.009700	$ 9.70	$ 9.70	$ 9.70
Rider A - Fuel Factor*	$ 0.031664	$ 0.031664	$ 31.66	$ 31.66	$ 31.66
Rider B - Biomass (A6)	$ -	$ -	$ -	$ -	$ -
Rider BW - Brunswick County (A6)	$ -	$ -	$ -	$ -	$ -
Rider C1A - (A5)*	$ 0.000245	$ 0.000245	$ 0.25	$ 0.25	$ 0.25
Rider C2A - (A5)***	$ -	$ -	$ -	$ -	$ -
Rider C4A - (A5)*	$ 0.001336	$ 0.001336	$ 1.34	$ 1.34	$ 1.34
Rider GV - Greensville (A6)**	$ -	$ -	$ -	$ -	$ -
Rider R - Bear Garden (A6)	$ -	$ -	$ -	$ -	$ -
Rider S - VCHEC (A6)	$ -	$ -	$ -	$ -	$ -
Rider T1 - Transmission (A4)*	$ 0.011789	$ 0.011789	$ 11.79	$ 11.79	$ 11.79
Rider U - Strategic Underground Program (A6)**	$ -	$ -	$ -	$ -	$ -
Rider W - Warren County (A6)	$ -	$ -	$ -	$ -	$ -
Rider E - Environmental Projects (A5)*	$ 0.001351	$ 0.001351	$ 1.35	$ 1.35	$ 1.35
Rider RGGI - (A5)	$ -	$ -	$ -	$ -	$ -
Rider RPS - (A5)*	$ 0.007676	$ 0.007676	$ 7.68	$ 7.68	$ 7.68
Rider CE - (A6)	$ 0.003668	$ 0.003668	$ 3.67	$ 3.67	$ 3.67
Rider CCR - Closure of Coal Combustion Residual Units (A5)*	$ 0.001183	$ 0.001183	$ 1.18	$ 1.18	$ 1.18
Rider PIPP - Percentage of Income Payment Plan ()*	$ -	$ -	$ -	$ -	$ -
Rider GT - Grid Transformation (A6)**	$ -	$ -	$ -	$ -	$ -
Rider SNA - Surry/NA Nuclear Life Extension Program (A6)*	$ 0.003475	$ 0.003475	$ 3.48	$ 3.48	$ 3.48
Rider OSW - Coastal Virginia Offshore Wind (A6)*	$ 0.011229	$ 0.011229	$ 11.23	$ 11.23	$ 11.23
Rider RBB - Rural Broadband Pilot Projects (A6)	$ 0.000531	$ 0.000531	$ 0.53	$ 0.53	$ 0.53
Deferred Fuel Cost Charge - Fuel Securitization	$ 0.003449	$ 0.003449	$ 3.45	$ 3.45	$ 3.45
Rider GEN - Generation Facilities Projects (A6)	$ 0.007564	$ 0.007564	$ 7.56	$ 7.56	$ 7.56
Rider DIST - Distribution Facilities Projects (A6)*	$ 0.006264	$ 0.006264	$ 6.26	$ 6.26	$ 6.26
Rider SMR - Small Modular Reactor (A6)*	$ 0.000289	$ 0.000289	$ 0.29	$ 0.29	$ 0.29
Rider CERC - Chesterfield Energy Reliability Center (A6)*	$ -	$ -	$ -	$ -	$ -
			$ 165.25	$ 160.57	**$ 162.13**
BLEND (SUMMER x 4 - NON-SUMMER x 8)			$ 661.00	$ 1,284.56	
AVG				**$ 162.13**	

*Pending SCC Approval
**The Company is requesting to withdraw Riders GT and U effective June 1, 2025. Going forward, costs associated with these projects will be recovered through Rider DIST.
***The Company is requesting to recover Rider C2A true-up costs through Rider C4A.