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PUBLIC VERSION

March 31, 2026

BY HAND DELIVERY

Mr. Bernard Logan, Clerk
c/o Document Control Center
State Corporation Commission
1300 East Main Street
Tyler Building – 1st Floor
Richmond, Virginia 23219

Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia
Case No. PUR-2026-00041

Dear Mr. Logan:

Please find enclosed for filing in the above-captioned proceeding an original and one (1) copy of the *Petition of Virginia Electric and Power Company and Request for Limited Waiver.* A confidential and extraordinarily sensitive version is also being filed under seal under separate cover.

Please do not hesitate to call if you have any questions regarding the enclosed.

Very truly yours,

/s/ Jontille D. Ray

Jontille D. Ray

Enclosures

cc: William H. Chambliss, Esq.
John E. Farmer, Jr., Esq.
Paul E. Pfeffer, Esq.
Lauren E. Wood, Esq.
Vishwa B. Link, Esq.
Etahjayne J. Harris, Esq.
Alexis S. Hills, Esq.

Petition of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia

PUBLIC VERSION

Volume 1 of 2

Case No. PUR-2026-00041

Filed: March 31, 2026

Petition of Virginia Electric and Power Company
For approval of a plan for electric distribution grid transformation projects
pursuant to § 56-585.1 A 6 of the Code of Virginia

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COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PETITION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	
	)	Case No. PUR-2026-00041
For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia	)	

PETITION OF VIRGINIA ELECTRIC AND POWER COMPANY AND REQUEST FOR LIMITED WAIVER

Pursuant to § 56-585.1 A 6 ("Subsection A 6") of the Code of Virginia ("Va. Code") and the Rules Governing Utility Rate Applications and Annual Informational Filings of Investor-Owned Electric Utilities (the "Rate Case Rules") of the State Corporation Commission of Virginia (the "Commission"), Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), by counsel, hereby files its petition for approval of a plan for electric distribution grid transformation projects (the "Petition"). Specifically, Dominion Energy Virginia asks for approval of Phase IV of its plan to transform its electric distribution grid (the "Grid Transformation Plan," the "GT Plan," or the "Plan"), which consists of proposed projects in the years 2027, 2028, and 2029.

Pursuant to Rule 10 E of the Rate Case Rules, the Company also requests limited waivers of the requirements of Rules 40 and 90 with respect to paper copies of certain Filing Schedule 46 materials.

In support of this Petition and request for limited waivers, the Company respectfully states as follows:

I. General Information

1. Dominion Energy Virginia 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 non-jurisdictional 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 a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. The Company is an operating subsidiary of Dominion Energy, Inc.

2. The Company's name and post office address are:

Virginia Electric and Power Company
600 E. Canal Street
Richmond, Virginia 23219

3. The names, addresses, and telephone numbers of the Company's attorneys are:

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II. Legal Authority

4. Subsection A 6, as amended by the Grid Transformation and Security Act of 2018 (the "GTSA"), requires the Company to petition the Commission for approval of a plan for electric grid transformation projects:

> A utility shall, without regard for whether it has petitioned for any rate adjustment clause pursuant to clause (vi), petition the Commission, not more than once annually, for approval of a plan for electric distribution grid transformation projects. Any plan for electric distribution grid transformation projects shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security.

5. Va. Code § 56-576 defines an "electric distribution grid transformation project" as follows:

> "Electric distribution grid transformation project" means a project associated with electric distribution infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage

information.

6. Subsection A 6 sets forth the standard for Commission review of a plan for electric distribution grid transformation projects:

> In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d.

7. Subsection A 6 also finds that electric distribution grid transformation projects are in the public interest.

8. In accordance with Subsection A 6, the Commission must issue its final order on a petition for approval of an electric distribution grid transformation plan not more than six months after the date of filing the petition.

III. The Grid Transformation Plan

9. Fundamental changes in the energy industry have prompted the need for electric utilities across the country to modernize their distribution grids. There is a paradigm shift that is creating a new set of current and future needs that must be addressed. The Virginia General Assembly recognized this need when it enacted the GTSA in 2018, establishing objectives for grid transformation and finding such projects to be in the public interest. Policy and market developments since then only accelerate the need for a modern distribution grid.

10. The Grid Transformation Plan is Dominion Energy Virginia's comprehensive plan to address these needs and meet the goals and objectives for grid transformation in a reasonable, prudent, and cost-effective manner. The Company presents the detailed summary of

its Grid Transformation Plan (the "GT Plan Document") as Exhibit 1 to this Petition. The GT Plan Document explains the need for a modern distribution grid, including industry developments from 2019 to 2025 supporting the continuing need for grid transformation. The GT Plan Document then reviews the Company's distribution planning process and explains how that process is evolving to meet the fundamental changes in the industry through integrated distribution planning. With this context, the GT Plan Document then presents an overview of the Grid Transformation Plan, including the process that led to its development. Finally, the GT Plan Document includes a look at future technologies and a quick-reference acronym list and glossary of terms used in the GT Plan Document itself and throughout this filing.

11. The Commission approved certain projects in Phase I of the Grid Transformation Plan—for the years 2019, 2020, and 2021—in Case Nos. PUR-2018-00100 and PUR-2019-00154. In addition, the Commission approved certain projects in Phase II of the Grid Transformation plan—for the years 2022 and 2023—in Case No. PUR-2021-00127. The Commission also approved certain projects in Phase III and Phase IIIB of the Grid Transformation Plan—for the years 2024, 2025, and 2026—in Case No. PUR-2023-00051 and PUR-2025-00051, respectively. The Company provides a status update on the successes of these projects to date through various witnesses, as applicable to this proceeding. Additionally, pursuant to the Commission's directive contained in its Phase III Final Order,[1] this Petition includes an Exhibit 2 presenting the Company's Annual Report on the Grid Transformation Plan.

12. In this Petition, the Company expands its work on several previously approved programs and introduces a new stepdown transformer conversion pilot program ("Stepdown

[1] *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2023-00051, Final Order (Sept. 18, 2023) ("Phase III Final Order").

Conversion Program").

13. Specifically, the Company is seeking approval of additional investment in its mainfeeder hardening, voltage island mitigation, voltage optimization enablement, telecommunications, and targeted corridor improvement ("TCI") programs. The Company proposes to continue the mainfeeder hardening program previously approved in Phases I, III, and IIIB of the GT Plan. In Phase IV, the Company proposes to continue the mainfeeder hardening project on 41 Company-identified feeders, which includes work from 2027 through 2029. The Company used the same reliability criteria used to select the previously approved projects, then selected 41 additional mainfeeders from the targeted mainfeeder hardening list, serving more than 93,000 customers and consisting of approximately 225 miles. The Company also seeks the continued implementation of and investment in voltage island mitigation, previously approved in Phases I, II, and III, and voltage optimization enablement, previously approved in Phases II and III. The Company proposes to complete four voltage island mitigation projects in Phase IV to reduce significant risks to approximately 6,986 customers, 12 critical services, and 1 Opportunity Zones. For voltage optimization enablement, Phase IV requests approval of continued voltage optimization enablement work affecting approximately 43,000 customer premises requiring substation voltage control upgrades and voltage improvements.

14. The Company further requests the continued deployment of its telecommunications plan previously approved in Phases I, II, and III. Specifically, Phase IV of the GT Plan proposes to continue its deployment of the Tier 2 network to extend high-speed connectivity and multi-protocol label switching ("MPLS") technology to an additional 38 critical facilities through Company-owned fiber. Finally, Phase IV also requests approval to continue its hazard tree removal and its tree overhang pilot programs, both of which constitute select

vegetation management programs as part of the larger TCI grid transformation project designed to improve grid reliability and resiliency and minimize environmental impacts.

15. In Phase IV, the Company also requests approval of one new project, the Stepdown Conversion Program. This pilot program is designed to proactively upgrade parts of the distribution system to a higher voltage, eliminating the need for the stepdown transformer. The pilot aims to eliminate 24 overhead 500 kVA and 333 kVA stepdown transformers that serve a population of customers that are 1) at risk of an extended outage and/or 2) served by lower voltages which limits the ability for these customers to pursue electrification or DER installations. This pilot program will proactively mitigate the risk of extended outages and expand access to electrification, battery storage, and solar. Company Witness Kathleen D. Staples provides more details regarding the Company's proposed investment in the Stepdown Conversion Program.

16. All proposed projects in this Phase IV Petition fall within the definition of an "electric distribution grid transformation project" as defined in Va. Code 56-576 and, thus, are deemed to be in the public interest.

17. Section IV.A of the GT Plan Document provides an overview of the need, benefits, and alternatives considered for each project, among other relevant information. Further information on each project, including the information required by the Rate Case Rules, is provided by the sponsoring Company witness. The total proposed investment associated with Phase IV of the GT Plan is $983.1 million in capital investment and $125.2 million in operations and maintenance investments. Company Witness Elizabeth B. Lecky presents an estimated long-term revenue requirement for the proposed Phase IV projects, as required by the Rate Case Rules.

18. The Company retained an independent, experienced, third-party partner, West Monroe Partners, LLC ("West Monroe"), to generate a cost-benefit analysis for the Grid Transformation Plan. Company Witness Danny Freeman of West Monroe presents testimony explaining that analysis and presenting the results. As summarized in Figure 5 in Section IV.D of the GT Plan Document, the proposed investments are beneficial to customers, with a benefit to cost ratio of 1.38 on a net present value ("NPV") basis.

IV. Supporting Testimony, Filing Schedule 46, and Request for Limited Waivers

19. In support of its Petition, the Company submits the pre-filed direct testimonies of Company Witnesses Augustus Johnson, IV, Ellen E. Jackson, Kathleen D. Staples, Bradley R. Carroll, Danny Freeman, and Elizabeth B. Lecky.

20. Rule 40 of the Rate Case Rules provides that a prudence determination petition pursuant to Chapter 23 of Title 56 "shall include Schedule 46 as identified and described in 20 VAC 5-201-90, and which shall be submitted with the utility's direct testimony." With this petition, the Company is submitting Filing Schedule 46 as follows:

a. Filing Schedule 46A consists of Statements 1 through 3. Filing Schedule 46A, Statements 1 and 2, are co-sponsored by Company Witnesses Johnson, Jackson, Staples, and Carroll. Filing Schedule 46A, Statement 1, provides a table showing where the Company has provided a detailed explanation of the justification for the proposed costs for which it seeks a prudence determination in Phase IV. Filing Schedule 46A, Statement 2, provides schedules of these projected and actual costs by type of cost and year, and by project.[2] Finally, Filing Schedule 46A, Statement 3, which Company Witness Johnson sponsors, provides support used by senior management for major cost decisions, as determined by the Company.

b. Filing Schedule 46B, consisting of Statements 1 through 3, is sponsored by Company Witness Jackson. Filing Schedule 46B, Statement 1, provides key documents supporting the projected and actual costs for mainfeeder hardening. Schedule 46B, Statement 2, provides key documents supporting the projected and actual costs for the voltage island mitigation. Filing Schedule 46B, Statement 3, provides key documents supporting the projected and actual costs for voltage

[2] The Company does not have this information available by month at this time.

optimization enablement.

c. Filing Schedule 46C, Statements 1 and 2, is sponsored by Company Witness Staples. Schedule 46C, Statement 1, provides key documents supporting the projected and actual costs for targeted corridor improvement. Schedule 46C, Statement 2, provides key documents supporting the projected and actual costs for the Company's newly proposed Stepdown Conversion Program.

d. Filing Schedule 46D, consisting of Statement 1, is sponsored by Company Witness Carroll. Filing Schedule 46D Statement 1 provides documents supporting the projected and actual costs for telecommunications.

e. Filing Schedule 46E, consisting of Statement 1, is sponsored by Company Witness Freeman. Filing Schedule 46E Statement 1 provides cost-benefit analysis results.

f. Filing Schedule 46F, consisting of Statements 1 and 2, is sponsored by Company Witness Lecky. Filing Schedule 46F, Statement 1, provides the estimated annual revenue requirement over the duration of the proposed Phase IV projects, by year and by project, on a total company basis. Filing Schedule 46F, Statement 2, provides a list of the workpapers that provide supporting calculations and assumptions for the estimated annual revenue. The Company requests to file these workpapers electronically for the reasons set forth below.

21. The Company, for good cause shown and pursuant to Rate Case Rule 10 E, respectfully requests that the Commission waive, in part, the requirements under Rule 40 and 90 of the Rate Case Rules with respect to paper copies of certain Filing Schedule 46 materials. Specifically, the Rate Case Rules require the Company to provide key documents supporting the projected and actual costs of the proposed projects, such as support used by senior management for major cost decisions as determined by the applicant, contracts, results from requests for proposals, and cost-benefit analyses.[3] The supporting documentation responsive to this requirement is voluminous and, often, not easily reviewed in hard copy (*i.e.*, paper) format. Accordingly, the Company seeks waiver of the requirement to file this information in hard copy. Instead, the Company proposes to file one hard copy of this supporting documentation

[3] 20 VAC 5-204-90, Schedule 46.d.1.ii.

accompanied by three compact discs ("CDs") with this documentation in electronic format, and provide this documentation to Commission Staff and any other future case participants in electronic format only. The Company will make these documents available via an electronic discovery site ("iManage Share") contemporaneously with this filing, with immediate access available to Commission Staff. This request for waiver is consistent with recent Commission orders granting similar limited waivers.[4] Should the Commission deny this request, the Company asks for a reasonable allowance of time to print the requisite filing copies of this material and submit it to the Commission prior to the Company's petition being deemed incomplete.

22. Further, for good cause shown and pursuant to Rate Case Rule 10 E, the Company respectfully requests that the Commission waive, in part, the requirements under Rate Case Rules 40 and 90 with respect to paper copies of supporting calculations for the estimated annual revenue requirement required as part of Filing Schedule 46. The Rate Case Rules require the Company to provide the estimated annual revenue requirement over the duration of the proposed project by year and by project, "including all supporting calculations and assumptions."[5] The Company has included the estimated long-term revenue requirement by project and by year as part of Schedule 46F, Statement 1. The calculations supporting the estimated annual revenue requirement calculation, however, are completed in Microsoft Excel, involve multiple worksheets and lines of data, and include formulas to complete the calculations. These workpapers are not easily converted to a printable version, and not easily reviewed in hard copy (*i.e.*, paper) format. For example, in hard copy, a reviewer cannot easily see the formulas and

[4] *See e.g, Petition of Virginia Electric and Power Company, For approval of its 2024 RPS Development Plan under § 56-585.5 D4 of the Code of Virginia and related requests*, Case No. PUR-2024-00147, Order on Motions at 5-6 (Sept. 12, 2024).
[5] 20 VAC 5-204-90, Schedule 46.d.2.ii.

calculations embedded in the Excel worksheets and how they interact. Accordingly, the Company seeks waiver of the requirement to file these workpapers in hard copy. Instead, the Company proposes to provide this documentation to Commission Staff and any other future case participants in electronic format only. The Company will make these documents available via iManage Share contemporaneously with this filing, with immediate access available to Commission Staff. Should the Commission deny this request, the Company asks for a reasonable allowance of time to print the requisite filing copies of this material and submit it to the Commission prior to the Company's petition being deemed incomplete.

V. Request for Confidential Treatment and Additional Protective Treatment for Extraordinarily Sensitive Information

23. The Company's Petition and accompanying schedules contain confidential and extraordinarily sensitive information as designated. Because portions of the Company's Petition contain confidential and extraordinarily sensitive information, in compliance with Rate Case Rule 10 F and Rule 170 of the Commission's Rules of Practice and Procedure, this Petition is accompanied by a contemporaneously-filed Motion for Entry of a Protective Order and Additional Protective Treatment, including a Proposed Protective Order.

VI. Compliance with Rule 10 of the Rate Case Rules

24. The Company's Petition complies with the requirements contained in Rule 10 of the Rate Case Rules.

25. In accordance with Rule 10 A, Dominion Energy Virginia filed with the Commission its notice of intent to file this Petition on January 13, 2026, and provided that notice to those listed in Rule 10 J 1, as required by that subsection.

26. The Company has included all information required by Rule 10 B in its Petition, including a table of contents, direct testimonies with one-page summaries, and properly labeled

exhibits and schedules.

27. In accordance with Rule 10 H, the Company will make a searchable PDF version of the Petition, direct testimonies, and Filing Schedule 46 available via iManage Share contemporaneously with this filing, with immediate access available to (i) Commission Staff, including identified members of the Divisions of Utility Accounting and Finance and Public Utility Regulation; and (ii) identified members of the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel").[6] Also in according with Rule 10 H, and consistent with the request for limited waiver in Paragraph 22 of this Petition, the Company will make electronic spreadsheets supporting the schedules that contain calculations—Company Witness Lecky's Schedule 1 and Filing Schedule 46F, Statement 1—available via iManage Share contemporaneously with this filing, with immediate access available to Commission Staff.

[6] Rule 10 J 3 requires the Company to provide a copy of the complete version of the Petition to Consumer Counsel at the same time it is filed with the Commission. As noted, pursuant to Rule 10 H, the Company will make a searchable PDF version of the Petition, direct testimonies, and Filing Schedule 46 available via iManage Share contemporaneously with this filing, with immediate access available to Consumer Counsel. The Company can provide a hard copy of the Petition to Consumer Counsel upon request to counsel.

VII. Request Regarding Discovery Deadline

28. Finally, the Company respectfully requests that the Commission allow all parties to the proceeding to have at least five to seven business days from receipt to respond to interrogatories or requests for production of documents. Measuring the discovery deadline in business days is consistent with the Commission's Rules of Practice and Procedure,[7] and accounts for intervening weekends and holidays. In addition, based on past experience, this proceeding likely will have a significant amount of discovery; allowing at least five to seven business days would allow the Company to better provide timely and complete responses. This request is consistent with the discovery timeline permitted in prior proceedings.[8]

VIII. Conclusion

WHEREFORE, Dominion Energy Virginia respectfully requests that the Commission: (i) approve Phase IV of the Grid Transformation Plan in its entirety as reasonable and prudent within six months of the date of this filing; (ii) grant the waiver requests outlined in this Petition of the filing requirements; (iii) grant the request for a discovery deadline of at least five to seven business days from receipt; and (iv) grant such other relief as deemed appropriate and necessary.

Respectfully submitted,

Virginia Electric and Power Company

By: /s/ Jontille D. Ray
Counsel

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[7] 5 VAC 5-20-140, -260 (setting the default rule at 10 business days for responses).
[8] *See 2023 Procedural Order* at 15 (setting the discovery timeline for responses at five business days).

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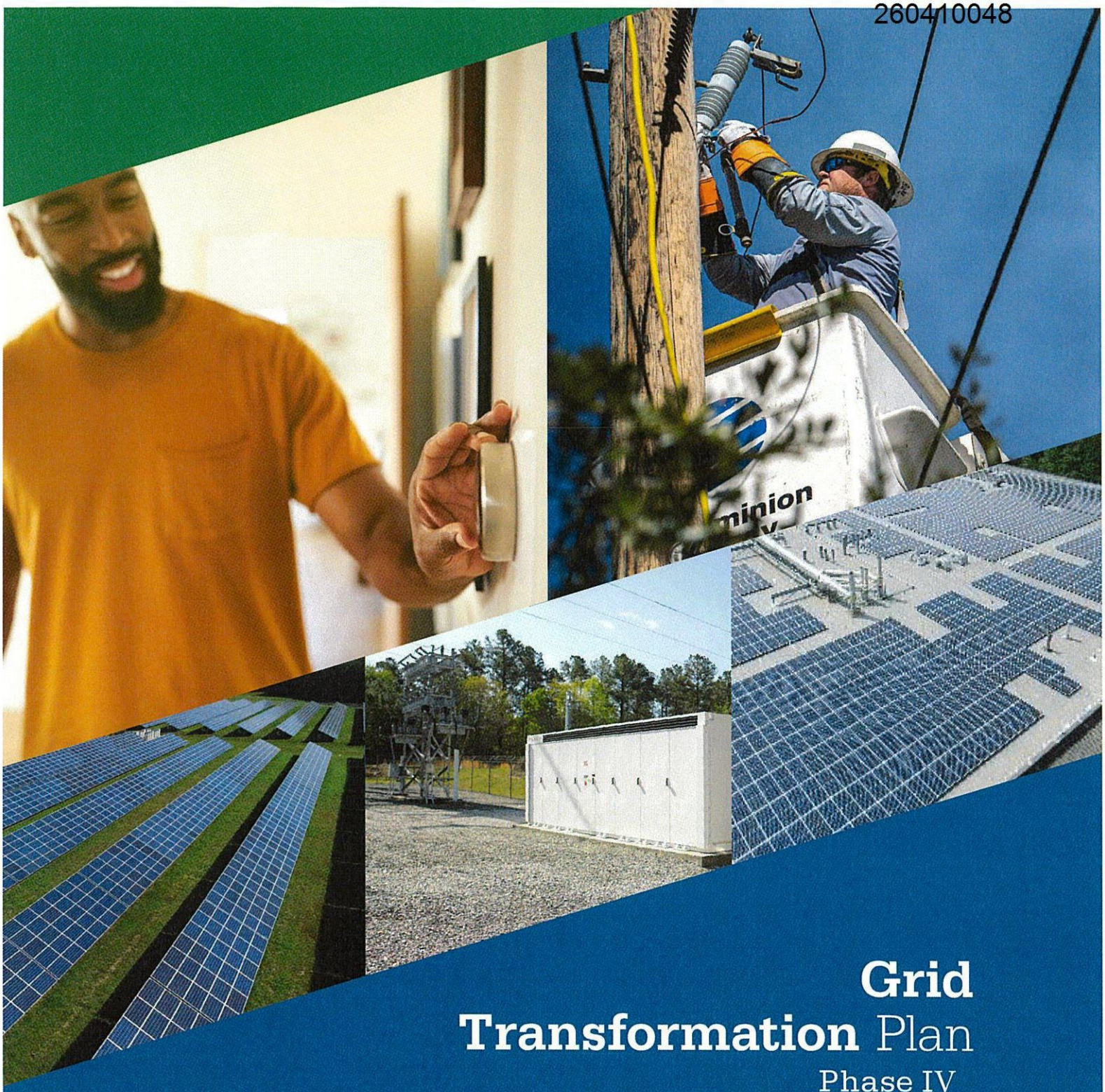
Counsel for Virginia Electric and Power Company

March 31, 2026

260410048

Exhibit 1

EXHIBIT 1



Grid Transformation Plan

Phase IV

Smart Energy

Dominion Energy®

Actions Speak Louder

Table of Contents

Introduction

Headquartered in Richmond, Virginia, Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") currently serves approximately 2.7 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company owns approximately 60,000 miles of distribution lines at voltages ranging from 4 kilovolts ("kV") to 46 kV in Virginia and North Carolina.

Dominion Energy Virginia first presented its plan to transform its distribution grid ("Grid Transformation Plan," "GT Plan," or "Plan") in 2018. Since then, the Company has engaged in an iterative process to refine its Grid Transformation Plan, incorporating feedback from the State Corporation Commission of Virginia (the "Commission"), Commission Staff, and other stakeholders, to devise the best strategy to meet the overarching goals of grid transformation—facilitating the integration of distributed energy resources ("DERs") and maintaining system reliability and security.

"Phase I" of the Grid Transformation Plan focused on grid transformation projects in the years 2019, 2020, and 2021.[1] "Phase II" of the GT Plan focuses on grid transformation projects in the years 2022 and 2023. "Phase III" and "Phase IIIB" of the Plan focus on grid transformation projects in the years 2024, 2025, and 2026.[2] Lastly, "Phase IV" of the plan focuses on grid transformation projects in the years 2027, 2028, and 2029. The Company anticipates additional future phases of the Grid Transformation Plan to continue the objectives and efforts of grid transformation.

The Company presented its first summary of the Grid Transformation Plan in 2019 and presented an updated summary in 2021, 2023, and 2025. This 2026 version updates the document to reflect industry developments supporting grid transformation, refinements to the Grid Transformation Plan, and the Company's progress with grid transformation efforts to date.

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[1] The Company has referred to "Phase IA" as projects approved by the Commission in Case No. PUR-2018-00100 and "Phase IB" as projects approved by the Commission in Case No. PUR-2019-00154.

[2] The Company has referred to "Phase IIIA" as projects approved by the Commission in Case No. PUR-2023-00051 and "Phase IIIB" as projects approved by the Commission in Case No. PUR-2025-00051.

Executive Summary

Fundamental changes in the energy industry have prompted the need for utilities across the country to modernize their distribution grids. With the passage of the Grid Transformation and Security Act of 2018 ("GTSA"), the Commonwealth of Virginia recognized this need, declaring electric distribution grid transformation to be in the public interest and mandating that utilities file a plan for grid transformation. The GTSA set forth two objectives for grid transformation: (i) facilitating the integration of DERs and (ii) enhancing grid reliability and security.

In response to this need, Dominion Energy Virginia prepared a comprehensive plan to transform its distribution grid to meet the changing landscape of the energy industry while continuing to provide the reliable service that its customers expect and deserve.

In Phases I and II of the Grid Transformation Plan, the Company pursued projects that are foundational to the vital objectives of grid transformation. From these initial investments the Company has seen notable successes that have a direct and positive effect on its customers. The Company has deployed advanced metering infrastructure ("AMI") to its customers in Virginia, enabling these customers to take control of their energy usage with the granular data that smart meters provide. The Company's new customer information platform ("CIP") went live in April of 2023, enabling the systems needed to modernize the customer relationship. The Company has enhanced grid reliability through multiple grid transformation projects, providing a direct benefit to customers and improving the availability of the grid for DERs. For example, customers served by the first forty-one feeders targeted through the Company's mainfeeder hardening program saw on average a 30% improvement in performance on mainline sections, avoiding more than 7.5 million minutes of interruption. And the Company has facilitated the integration of DERs through, for example, the launch of two hosting capacity tools that provide guidance to customers and developers about siting clean energy installations, and through its rebate program for the installation of smart charging infrastructure for electric vehicles ("EVs").

The passage of time continues to validate the need for the Grid Transformation Plan. In previous phases the Company discussed the policy and market developments that would accelerate the shift toward DER, including the issuance of FERC Order 2222 regarding DER aggregation for participation in regional markets and the passage of the Virginia Clean Economy Act of 2020 ("VCEA") calling for the development of significant amounts of distributed solar and energy storage and expanding opportunities for net metering in the Commonwealth. The Company has seen this shift, with a 62% increase in solar interconnections (by MW) between year-end 2021 and year-end 2025, a 178% increase in net energy metering customers, and a 312% increase in customers with EVs in the Company's service territory. In addition, major weather events and physical attacks continue to show that more work is needed to achieve the objectives of grid transformation.

In Phase III, the Company sought and obtained Commission approval to continue its work on approved projects toward the objectives of grid transformation based on the same need that has been shown in prior proceedings. Specifically, the Company completed the deployment of two foundational GT Plan investments—AMI and the CIP. The Company also continued its three grid infrastructure projects approved by the Commission in prior phases—mainfeeder hardening,

targeted corridor improvement, and voltage island mitigation—along with three of its previously approved grid technologies projects—a DER management system ("DERMS"), voltage optimization enablement, and substation technology deployment. Together, these investments will continue to enhance grid reliability and facilitate the integration of DERs. Finally, the Company continued investing in enhanced telecommunications and physical substation security, as well as investments in cyber security and customer education as needed to support other projects.

Additionally, in Phase III, two new projects were approved. First, the Company is deploying a new outage management system ("OMS") to replace an outdated operating system that cannot accommodate the complexity that a modern distribution grid requires. The new OMS is also needed to leverage the full benefits of other GT Plan investments, such as AMI, intelligent grid devices, and fault location, isolation, and service restoration ("FLISR") software. Second, the Company received approval of a pilot to evaluate energy storage systems as non-wires alternatives ("NWAs") to traditional distribution investments. This pilot will enable the Company to gain experience with this integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with NWAs which may result in the integration of energy storage systems that can dynamically respond to changing grid conditions.

In Phase IIIB, the Company received approval to continue its work on approved projects toward the objectives of grid transformation based on the same need that has been shown in prior proceedings. Specifically, the Company was approved for additional investments in mainfeeder hardening and OMS. The Company also received approval of one new project, a remote sensing-based Image Management and Analytical Program ("iMAP"). iMAP will provide the Company with more information about the current state of its assets to enable more efficient and proactive maintenance, while helping to prevent and reduce the duration of outages.

Lastly, in Phase IV, the Company seeks to expand its work in several previously approved programs as well as introduce a new stepdown transformer conversion pilot program ("Stepdown Conversion Program"). Specifically, the Company is seeking approval of additional investment in its Mainfeeder Hardening, Voltage Island Mitigation, Voltage Optimization Enablement, Telecommunications, and Targeted Corridor Improvement programs. The Stepdown Conversion Program will improve service reliability, mitigate risk of an extended outage, and expand access to electrification and distributed energy resources to customers served by stepdown transformers at a high risk of failure.

This document provides a guide through the need for grid modernization (Section I), the Company's distribution grid planning process (Section II), and the development of the Grid Transformation Plan (Section III). This document also provides an overview of the Plan itself (Section IV), including the accurate and reasonable cost estimates for each project based on competitive bidding processes and the quantitative and qualitative benefits of the proposed projects. The Grid Transformation Plan represents the optimal package to facilitate the integration of DERs while maintaining and enhancing reliable and secure electric service.

I. Need for a Modern Distribution Grid

Electricity has become a basic need, vital to our economy, public safety, and way of life. Critical services and infrastructure increasingly rely on electricity, including homeland security, medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pump facilities. The transportation industry is actively continuing its shift toward electrification of personal vehicles, fleets, and mass transit. Another vital resource powered by electricity is the internet, which drives commerce and everyday life. As society has grown more dependent on electricity, customers expect highly reliable service. The critical need for reliable electric service became even more acute in 2020, when life for many Americans—including commerce, education, and health—shifted to the home, and the internet, because of the pandemic. While service interruptions have always been an inconvenience, the safe, reliable, and consistent grid connectivity has never been more important than it is today. With policy and climate change initiatives important to the Company and the Commonwealth, electricity should also be increasingly clean.

A. Context for Distribution Grid Transformation

The electric grid was originally designed for the one-way flow of electricity, with electricity moving from large, centralized generators through high-voltage transmission lines to the distribution system. On the distribution system, electricity flowed from the substation to the customer. While originally limited to cities, the electric power grid eventually reached even the most remote areas of the country as a result of the incentives provided in the Rural Electrification Act of 1936 for the installation of distribution systems in isolated rural areas of the United States. A comprehensive description of Dominion Energy Virginia's existing distribution grid is provided as Appendix A.

As reliance on electricity grew, focus shifted to the transmission system as vital to reliability of the electric grid as designed (*i.e.*, the one-way flow of electricity). The Northeast Blackout of 2003 drove new standards and investments into the transmission grid. The North American Electric Reliability Corporation ("NERC") became the national electric reliability organization responsible for the reliability of the transmission system and instituted mandatory minimum standards to which transmission owners had to plan.

In the current day, focus has now shifted to DERs. The term "DER" encompasses all manner of resources, including solar and wind generation, energy storage, and EVs. As the Department of Energy's Office of Electricity noted in a 2019 report, "[m]any parts of the country are experiencing fundamental changes in customer expectations for distribution grid performance, with a large number of customers utilizing the grid to integrate DER and other new technologies or seeking a platform for market transactions."[3]

The rise of DERs requires a fundamental change to the electric grid. With DERs, electricity is now flowing onto the distribution system from multiple points. The distribution system that was

[3] Department of Energy's Office of Electricity, MODERN DISTRIBUTION GRID (DSPX) VOLUME I: OBJECTIVE DRIVE FUNCTIONALITY at 16 (Nov. 2019) [hereinafter DOE REPORT], *available at* https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_I_v2_0.pdf.

designed for the one-way flow of electricity must now accommodate the dynamic flow of electricity. In addition, the intermittent nature of some of these resources resulting from weather variability creates power fluctuations not typical of traditional generation resources. Propagated in an arbitrary manner, DERs are independent nodes that can disrupt traditional grid power quality and reliability. But when paired with investments to increase visibility, reliability, and resiliency on and control of the distribution system, the grid can transform DERs into a system resource that can be equitably managed to maximize the value of other available resources, to potentially offset the need for future "traditional" generating assets or grid upgrades, and to maintain reliable service to customers. In addition, because DERs rely on the distribution system to deliver the electricity they produce, a resilient distribution system is vital to maximizing the value of DERs. Day to day outages as well as major weather events not only cause prolonged outages for customers, but also prevent DERs from delivering electricity. The distribution system must be reliable and resilient so that it can operate for DERs like the transmission system operates for large, centralized generators. As the Electric Power Research Institute ("EPRI") has outlined, the distribution grid benefits DER through (i) reliability; (ii) startup power; (iii) voltage quality; (iv) efficiency; and (v) energy transaction.[4]

And throughout, severe weather and man-made events continue as a reality across the country. The value of resiliency investments in response to such events has been demonstrated both by the Company and by peer utilities, enabling timely restoration and economic recovery when damage does occur.

B. Developments Supporting Grid Transformation—2019 to 2025

From 2019 to 2025, numerous federal, state, and industry developments reinforced the need to modernize the electric grid.

At the federal level, FERC Order 2222 (2020) opened wholesale market participation to aggregated DERs—including storage, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles—requiring Regional Transmission Operators ("RTO") to integrate these resources on equal footing with traditional assets. Additional federal momentum came through major legislation: the Infrastructure Investment and Jobs Act of 2021, which introduced significant funding opportunities for grid modernization, reliability, and resilience, and the Inflation Reduction Act of 2022, which expanded tax incentives supporting clean energy and DER deployment.

In Virginia, the Virginia Clean Economy Act (2020) accelerated DER adoption, calling for 1,100 MW of small-scale solar, 2,700 MW of energy storage, expanded net metering opportunities, and new regulations supporting behind-the-meter storage and non-wires alternatives. In 2022, the state's updated Virginia Energy Plan emphasized reliability as the foremost priority for the Commonwealth's energy future. Parallel legislative actions in 2021 promoted transportation electrification, including EV rebates and manufacturer requirements, resulting in increased EV

[4] American Public Power Association, THE VALUE OF THE GRID (Jul. 2018), *available at* https://www.publicpower.org/system/files/documents/Value%20of%20the%20Grid_1.pdf (citing EPRI, THE INTEGRATED GRID: REALIZING THE FULL VALUE OF CENTRAL AND DISTRIBUTED ENERGY RESOURCES (2014)).

charging infrastructure connected to the distribution grid. Additionally in 2025, Virginia's HB 2346 was signed into law,[5] establishing a statewide initiative to modernize the electric grid by requiring utilities to implement Virtual Power Plant pilot programs. This legislation positions distributed energy resources as coordinated assets that can support grid reliability, reduce peak demand, and lower energy costs.

Nationwide, both policy direction and real-world events underscored the urgency of grid transformation. The federal administration's 2021 support for EVs, combined with growing adoption across states, increased demand for distribution connected charging infrastructure. At the same time, severe weather, physical attacks on grid infrastructure, and other threats highlighted ongoing vulnerabilities, reinforcing the need for a more resilient, secure, and flexible grid. Industry groups also advanced this transition. Notably, a joint NARUC–NASEO task force (2019–2021) called for reimagined electricity system planning to optimize DERs, strengthen reliability, avoid unnecessary costs, support state policies, and improve transparency in grid investment decisions.

Collectively, these developments demonstrate a clear and increasing national and state-level push toward a modern, resilient, customer-centric grid capable of integrating growing DER adoption, electrification, and emerging technologies.

C. DER Growth

The Company has seen continuous growth in DERs over the past several years. For example, for larger-scale DERs as of December 31, 2025, there are 119 interconnection requests for solar generation sites totaling 758 MW with executed interconnection agreements that are in the construction process, and 653 requests totaling 3,891 MW that are at some level of evaluation under the state interconnection process. This compares to a total of 89 utility-scale solar generation sites totaling 852 MW connected to the Company's distribution system in Virginia as of year-end 2025.

Looking at smaller DERs, the Company has seen the number of net energy metering ("NEM") customers grow from approximately 2,100 in 2016 to over 55,600 through 2025, more than a 2500% increase in that nine-year period. In 2025 alone, the Company facilitated interconnection of over 7,100 unique net metering installations. As of December 31, 2025, the Company supports over 55,600 net metering customers with a collective capacity of over 503 MW in its Virginia service territory. Similar growth trends can be seen related to EVs, with greater than 114,000 customers in the Company's service territory having switched to electric.

The Company expects this DER growth to continue with the market developments and supportive public policies discussed in Section I.B. Based on current forecasts, the Company expects both solar interconnections on the distribution grid and net energy metering installations to total more than 1,600 MW, and projects over 480,000 customers switching to EVs by the end of 2029.

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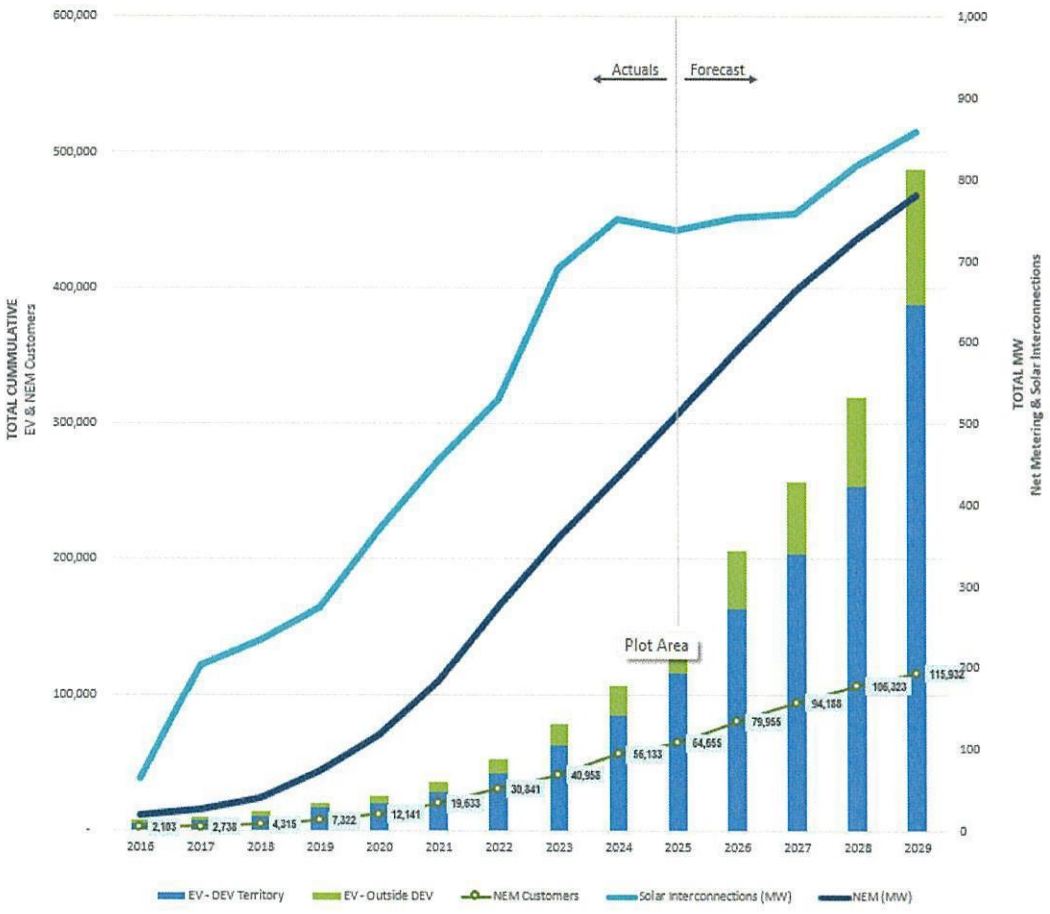
[5] Va. Code §56-585.1:16.

Figure 1 shows the actual growth in DERs between 2016 and 2025 as well as the forecasted growth in DERs for the next five years.

Figure 1: DER Growth in Dominion Energy Virginia Service Territory



Propagated in an arbitrary manner, DERs can disrupt grid power quality and reliability. Yet the investments outlined in the Grid Transformation Plan combined with the evolution of the Company's integrated distribution planning process seek to ensure that any potential adverse impacts will not occur. Specifically, the completed and planned GT Plan investments to increase visibility, reliability, and resiliency on and control of the distribution system enables the Company to transform DERs into system resources. In addition, combining the data generated from these investments with new modeling methodologies and advanced analytics will enable the Company to generate detailed forecasts for new DERs and load—along with simulations of the potential impacts of new DERs and load on the grid—to plan for the future needs of the grid and to address those needs before adverse impacts occur.

D. Value of a Transformed Distribution Grid to Customers

Foundational investments to transform the distribution grid allow the Company to use the distribution system differently than it has historically, all for the benefit of customers. Transformational investments in AMI, the CIP, intelligent grid devices, and automated control systems enable the Company to improve operations (*e.g.*, reduced truck rolls; more predictive and efficient maintenance; increased visibility and control; optimized use of DERs), better forecast load shape, and predict future behaviors (*e.g.*, identifying and fixing grid problems before an outage occurs, enabling overall savings and cost management of demand-side management ("DSM") programs), resulting in a better, more informed customer experience. This value of a transformed distribution grid can be seen from the view of different types of customers.

Prior to grid transformation, all customers had to take specific action to report outages and then wait for the Company to deploy resources to bring the power back on. With transformational investments in AMI, CIP, intelligent grid devices, automated control systems (*e.g.*, OMS, FLISR), and resilience, customers will experience fewer outages and will not need to take action to report outages when they do occur. Instead, when outages do occur on the more connected and resilient grid, the outages reported through smart meters and other intelligent grid devices will prompt the dynamic system to automatically restore power to as many customers as possible, narrowing the scope of the outage and focusing effort on issues that require manual intervention. Additionally, grid visibility provided by the transformed grid will allow customers to receive proactive outage and restoration alerts—and more accurate information on expected restoration times, including detailed outage maps—allowing the fewer customers that are impacted to better adapt to the situation.

Prior to grid transformation, most residential customers received monthly energy usage data at a summary level through their bills. With transformational investments in AMI and the CIP, all residential customers can receive detailed interval energy usage data through convenient communication channels. The corresponding education will inform customers on how to take control of and manage their energy usage, if desired. These customers also have the opportunity to participate in time-varying rates and innovative DSM programs that these investments enable the Company to broadly offer. Such rate options and DSM programs can prompt behavioral changes that benefit customers through bill savings and reduced system costs. Indeed, customers have already begun to take advantage of these opportunities, with more than 13,700 customers enrolled in the Company's experimental time-of-use rate, the Off-Peak Plan (*i.e.*, Schedule 1G), and more than 2.7 million email addresses added as a convenient communication channel for customers. Further, with transformational investments in voltage optimization, informed by the data from AMI and intelligent grid devices, most customers will see lower energy consumption without a noticeable difference in service level because of the more precise voltage control settings.

Prior to grid transformation, multi-family complex customers (*e.g.*, apartment complexes) had meters that limited the efficiency of the move-in / move-out process, a process that happens more frequently than for single-family homes. With transformational investments in AMI and the CIP, customers can change accounts the same day, leading to more efficient relocation, easier owner / tenant billing, and lower costs.

Prior to grid transformation, DER net metering customers had to engage in a largely manual application process and then wait for a meter exchange. The meter exchange process alone could take up to 10 business days to schedule and complete, leading to potential interconnection delays for the customer. With transformational investments in AMI, CIP, intelligent grid devices, a DER management system ("DERMS"), and resilience, DER customers will (i) experience a much faster and seamless interconnection process, (ii) will no longer need a meter exchange, and (iii) will receive detailed information on how their DERs interact with the grid. Further, customers will maximize the value of their DERs through the connection with a resilient grid, and through opportunities to offer their DERs into programs that provide grid support or other functions. In addition, transformational grid investments have enabled a hosting capacity map that allows customers, and even localities, to evaluate optimal locations to interconnect DERs—a map that will continue to become more dynamic as additional AMI and intelligent grid devices are added to improve grid visibility. By empowering customers with the information to optimally locate DER, customers can realize reduced interconnection costs and potentially contribute to the deferral of other system investments.

Prior to grid transformation, the majority of EV customers did not have attractive options to encourage them to charge their vehicles during times when the demand for electricity is low. With transformational investments in AMI, CIP, and smart charging infrastructure, EV customers have access to more innovative programs and advanced rate options, such as the Company's Off-Peak Plan that can lead to bill savings and reduced system costs.

Prior to grid transformation, business customers were subject to sudden voltage fluctuations when outage events occurred on the distribution grid. Even when a customer did not experience a sustained outage, these voltage fluctuations have the potential to impact operational processes and facility production. The intermittency and changing power flows related to renewable generation introduce new dynamics to grid operation that, if not managed properly, have the potential to similarly impact these customers. Transformational investments in reliability and resiliency will eliminate certain outage events and the associated voltage fluctuations that ripple across the distribution grid, while also ensuring power is restored more quickly when it does go out. With transformational investments in AMI, intelligent grid devices, and automated control systems, the Company has the situational awareness and control capabilities to manage grid operation so business customers can rely on voltage stability to ensure minimal disruption to their operations.

Prior to grid transformation, vital community resources are more dependent on grid reliability than ever before. Health and safety services, such as hospitals, water, and emergency services, carry the highest priority day-to-day and in a restoration event, closely followed by commerce and education, including internet services for home and work. More grid availability translates to availability for DER to contribute to system resources in the form of capacity factor. With transformational investments in resilient grid architecture, customers will have confidence that their growing reliance will be served.

Dominion Energy Virginia values the experience of its customers and believes that the Grid Transformation Plan will enable the Company to meet their changing needs and expectations.

II. Distribution Grid Planning

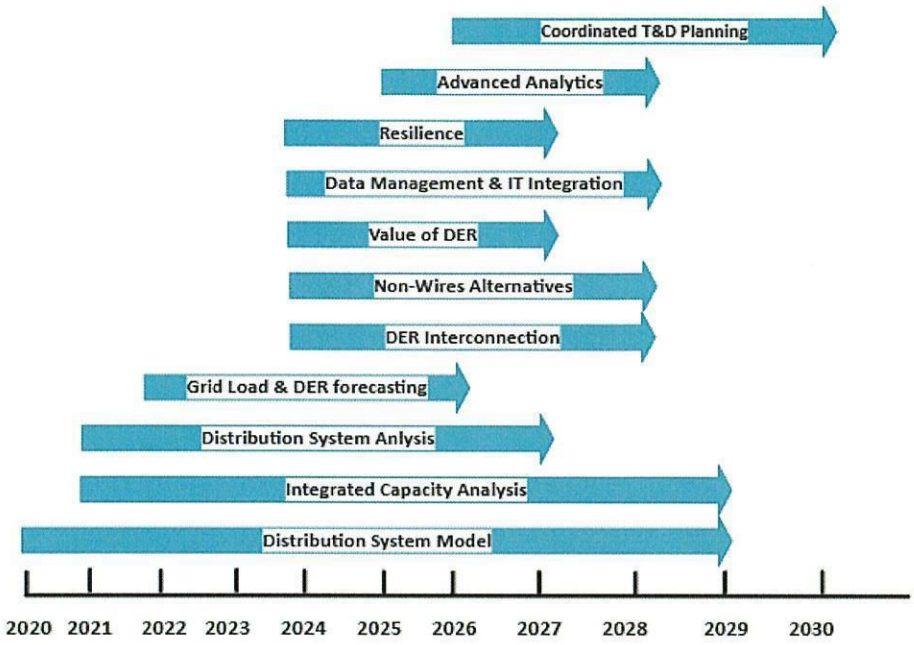
The fundamental changes in the energy industry discussed in Section I have driven not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs.

In 2019, the Company presented a white paper that provided a conceptual first-look at its transition toward integrated distribution planning ("IDP"). The Company defines integrated distribution planning as a consolidated process to address the capacity, performance, reliability, resilience, and DER integration needs of the distribution grid. The white paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution system. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including successes related to people, such as the centralization of its organizational structure such that the one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments; technologies, primarily through development and implementation of Grid Transformation Plan investments; and processes, such as the development of an initial forecast of DERs by feeder and publications of hosting capacity maps for different types of DERs.

In 2021, the Company noted its continued work on a roadmap for IDP that adds tangible goals and timeframes to IDP maturity and presented that roadmap in 2023. The Roadmap updates tangible goals for the components of IDP on which the Company plans to focus in the near term. Figure 2 provides a visual representation of the updated Roadmap.

Figure 2: IDP Roadmap



The IDP concept is not static, and further changes are expected in the next decade. But the IDP Roadmap sets the Company on a trajectory to give higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements, while balancing the resources required to implement these components and the interdependencies among many of the components. The Company continues to diligently work on the IDP Roadmap, ensuring that these priorities are met, and progress is sustained.

III. Development of Grid Transformation Plan

The Company has engaged in an iterative process to develop the Grid Transformation Plan presented in this document. Guided by the policy objectives of the Commonwealth to facilitate the integration of DER and enhance distribution grid reliability and security, the Company incorporated its experience-based knowledge with input from customers and stakeholders; with lessons from the experiences of peer utilities; and with guidance provided by the Commission in prior orders.

A. Internal Process

The Company consistently tracks developments in the energy industry and challenges for its distribution system. The Company collaborates with its peer utilities and learns from their experiences. The Company keeps current with information published by various industry groups and has engaged with these industry groups to gain additional knowledge and perspective. The Company also continues to engage an industry expert, West Monroe Partners, as a knowledgeable partner in the development and implementation of a plan to modernize the distribution grid. The Company intentionally tests certain components of the GT Plan on a smaller scale prior to full scale deployment, such as AMI and mainfeeder hardening. And the Company continuously incorporates lessons learned from prior GT Plan investments into its strategy for deployment of GT Plan investments into the future. All this knowledge coalesced to create the framework for and to ensure prudent implementation of the Grid Transformation Plan.

B. Customer Engagement

Dominion Energy Virginia strives to meet its customers' energy needs while providing a seamless customer experience. To that end, the Company frequently seeks feedback from its customers in various forms and forums. The Company has also sought specific feedback to assist in the development of the Grid Transformation Plan. The Company intends to continue this customer engagement to assess the priorities included in the GT Plan.

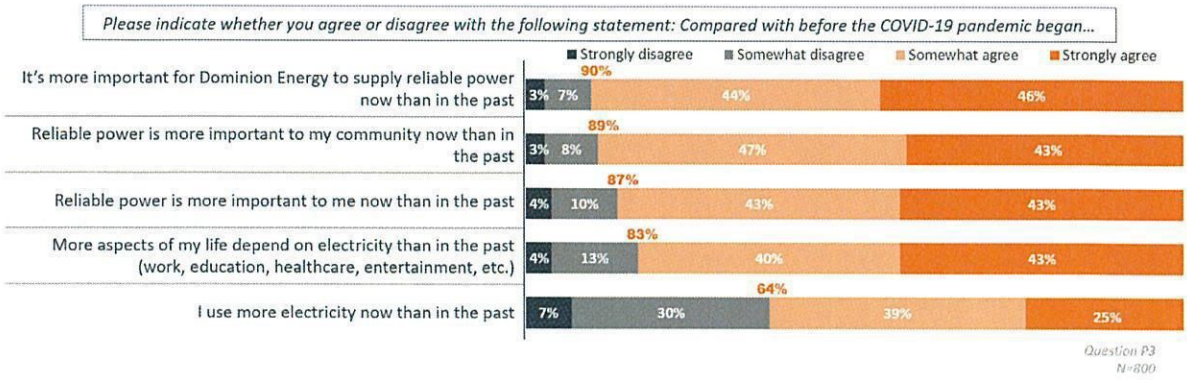
The Company receives customer feedback on a daily basis. The Company strives not only to quickly and fairly resolve any customer issue, but also to identify trends and possible process improvements. The Company will continue to engage with customers on an ongoing basis in its efforts to meet customer needs and expectations.

In 2019, the Company presented the results of a survey conducted by Maslansky + Partners ("Maslansky") to evaluate customer priorities related to the Grid Transformation Plan. Maslansky based this effort on a nationwide survey fielded by Edison Electric Institute ("EEI") on the "Voice of the Customer," and, where applicable, compared the results of the Virginia survey and the national study. In 2021, the Company contracted with an external third-party to conduct enterprise-wide and Virginia-based research to evaluate customer priorities.

To further understand and confirm customer priorities, in 2023, the Company engaged Maslansky to conduct an updated survey to evaluate customer priorities related to the Grid Transformation Plan, with a focus on customer expectations around reliability in light of the pandemic. The survey indicated that customers report the value of reliable energy has increased

since the pandemic, with 90% of customers surveyed agreeing that "it's more important for Dominion Energy to supply reliable power now than in the past." Figure 3 shows the results of this survey related to the importance of and dependence on reliable energy.

Figure 3: Maslansky Findings on Importance of and Dependence on Reliable Energy



C. Stakeholder Engagement

In furtherance and development of the Company's GT Plan and related initiatives, the Company began a series of stakeholder sessions in mid-2019 to inform and develop goals for a modern grid and the customer experience.

Ahead of its Grid Transformation Plan filing in 2019, the Company engaged an industry expert, Navigant, to facilitate an external stakeholder process. Attendees included a range of stakeholders with varying interests, from environmental advocates to municipality representatives to low-income advocates. Commission Staff also attended the stakeholder process. Navigant facilitated a series of workshops that guided the conversation on the stakeholders' vision and objectives for grid transformation. Through collaborative conversations, a group of the stakeholders identified four goals for grid transformation:

- **Optionality**: Enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access.
- **Sustainability**: Evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles.
- **Resiliency**: Build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management.
- **Affordability**: Deliver value for customers by optimizing demand and seeking to reduce system and customer costs.

Using these goals as a guide, Navigant led an exercise for stakeholder groups to prioritize grid capabilities that any plan for grid transformation should enable. Consistent across all stakeholder groups were investments that enabled two capabilities: (i) integrate and optimize DERs and (ii) provide relevant, data-enabled options that enable customers to meet their goals. In addition, highly prioritized by at least one stakeholder group were investments that enabled the following

capabilities: (iii) increase monitoring and visibility; (iv) accommodate two-way power flows; (v) enable voltage monitoring and control, supporting load management and peak shifting; (vi) simplify interconnection for residential customers; and (vii) harden for resiliency and security.

Ahead of the Grid Transformation Plan filing in 2021, the Company re-convened stakeholders to provide an update and opportunity for feedback on various GT Plan components over three sessions. The first session focused on AMI, the CIP, and other customer-related programs such as the Company's Schedule 1G (marketed as the Off-Peak Plan). The second session focused on the Company's approved Smart Charging Infrastructure Pilot Program and other electrification initiatives. The third session focused on the Company's proposed intelligent grid device deployment and DERMS, and how the GT Plan more generally supports the objectives of the VCEA. Attendees at these sessions included a range of stakeholders with varying interests, from environmental advocates to state agency representatives to low-income advocates. Commission Staff also attended the stakeholder process.

Ahead of the 2023 Grid Transformation Plan filing, the Company again re-convened stakeholders to provide an update and opportunity for feedback. The Company provided status updates on specific projects of interest from Phases I and II, including AMI, the CIP, targeted corridor improvement, mainfeeder hardening, substation technology deployment, intelligent grid devices, and physical security. The Company also provided a preview of projects for which it planned to seek approval in Phase III, including the NWA Program. The Company invited Commission Staff, respondents from prior GT Plan proceedings, and other stakeholders with varying interests, including state agency representatives and low-income advocates, to this session.

Through periodic updates and proactive communications on new GT programs and technologies, the Company intends to continue engagement with customers and external stakeholders as its grid transformation efforts proceed.

D. Environmental Justice Evaluation

Under the Virginia Environmental Justice Act ("VEJA"), environmental justice is defined as the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy. The primary tenets of the VEJA—fair treatment and meaningful involvement—were not created anew in the Commonwealth, but instead stand and build upon existing, governmental environmental justice policies stemming back to Executive Order 12898 issued by President Clinton in 1994. This Executive Order focused on disproportionately high and adverse human health or environmental effects, including high risks from environmental hazards and impacts on populations relying on subsistence lifestyles, of federal agencies' actions on minority populations and low-income populations.[6]

Like its federal predecessor, under the VEJA, "fair treatment" focuses on the negative and adverse environmental impacts of a project, and is defined to mean "the equitable consideration of all people whereby no group of people bears a disproportionate share of any negative environmental

[6] Executive Order 12,898 §§ 1-101, 3-301, 4-401 (Feb. 16, 1994), *available at* https://www.archives.gov/files/federal-register/executive-orders/pdf/12898.pdf.

consequence resulting from operations, programs, or policies." Similarly, "meaningful involvement" under the VEJA means "the requirements that (i) affected and vulnerable community residents have access and opportunities to participate in the full cycle of the decision-making process about a proposed activity that will affect their environment or health and (ii) decision makers will seek out and consider such participation, allowing the views and perspectives of community residents to shape and influence the decision." The VEJA defines "environment" broadly to mean "the natural, cultural, social, economic, and political assets or components of a community."

Dominion Energy Virginia is dedicated to meeting environmental justice expectations of fair treatment and meaningful involvement by being inclusive, understanding, and dedicated to finding solutions, and by effectively communicating with its customers and neighbors. The Company adopted an environmental justice policy in 2018 through which it committed to hearing, fully considering, and responding to the concerns of all stakeholders. Consistent with the VEJA, this commitment includes ensuring that a voice in decisions about siting and operating energy infrastructure is given to all people and communities. Communities should have ready access to accurate information and a meaningful voice in the project development process. The Company has pledged to be a positive catalyst in its communities.

Generally, when conducting an environmental justice review, one evaluates: the type of activity (*e.g.*, a project or program at issue); where it will occur; what type of environmental impacts are likely; if any impacts, are they negative or adverse; and, whether there are environmental justice communities (as that term is defined by the VEJA) that might suffer the negative or adverse environmental impacts of the proposed activity. These factors are consistent with the VEJA, U.S. Environmental Protection Agency guidance, and currently accepted best practices. The VEJA defines environmental justice communities as identifiable, discrete communities within a specific geographic area. For example, the definition of "community of color" focuses on "any geographically distinct area," and the definition of "low-income community" focuses on "any census block group."

The outcome of one or more of the inquiries in a typical environmental justice review may result in a finding that no environmental justice concerns exist. For example, a proposed project to upgrade a computer system may not have an environmental impact on any community, let alone an environmental justice community. As noted above, the VEJA defines environmental justice communities as identifiable, discrete communities within a specific geographic area. Thus, in this example, because a discrete environmental justice community is not at issue, the environmental justice review under the VEJA would be at an end. Assuming there is an environmental justice community that might suffer negative environmental impacts of the proposed activity, then an analysis is done to determine whether that community would bear a disproportionate share of such impacts. As discussed below, in preparing the Grid Transformation Plan, Dominion Energy Virginia evaluated each proposed project to determine whether any environmental justice concerns exist.

The Grid Transformation Plan (GT Plan) encompasses multiple projects, some requiring community work within the Company's service territory and others not. While all projects aim to benefit these communities and customers broadly, the Company remains committed to

environmental justice. The following Phase IV projects require some community work: mainfeeder hardening, voltage island mitigation, telecommunications projects, targeted corridor improvement, and the stepdown transformer conversion pilot program. A third-party consultant was engaged to evaluate the aforementioned projects, informing the Company's environmental strategy for the GT Plan.

As the GT Plan evolves, with some programs dating back to 2019, the Company is committed to providing progress updates and engaging in outreach to inform customers and stakeholders about new program offerings.

IV. Grid Transformation Plan

Virginia Code § 56-585.1 A 6 requires that any plan for electric distribution grid transformation projects "shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security." Based on the development process described in Section III, the Company presents a comprehensive plan designed to achieve all the goals and objectives for grid transformation in a reasonable, prudent, and cost-effective manner.

At its inception, the Grid Transformation Plan includes six core components: (i) AMI; (ii) CIP; (iii) grid improvements within two categories, grid infrastructure and grid technologies; (iv) transportation electrification; (v) security; and (vi) telecommunications infrastructure.[7] Certain components, such as grid improvements, consist of multiple electric distribution grid transformation projects. The Plan also incorporates customer education related to the Company's grid transformation efforts generally, and to specific projects.

A. Projects

The sections that follow provide an overview of each project currently incorporated into the Grid Transformation Plan and summarize the need for the specific project, the deployment timeline, the alternatives considered, and the benefits. Refer to Appendix A as needed for context, which provides a description of the existing distribution grid. Finally, each section provides an overview of the Company's progress to date on the project, if applicable. These sections are intended to provide a high-level overview.

1. Grid Infrastructure

Within the category of grid infrastructure, the Company is: (a) hardening mainfeeders; (b) deploying targeted corridor improvement activities; (c) mitigating voltage islands; and (d) converting stepdown transformers.

[7] AMI-centric and Transportation Electrification investments and all respective programs, as well as the CIP are no longer a part of the GT Plan.

a. Mainfeeder Hardening

Dominion Energy Virginia continues to complete hardening work (*i.e.*, physically strengthening infrastructure, improving distribution system architecture and connectivity) on a targeted population of mainfeeders.

- Need. Improve reliability on the worst performing mainfeeders.
- Deployment Timeline. Harden 195 mainfeeders through completion of the GT Plan.
- Alternatives Considered. Considered addressing issues on the identified mainfeeders reactively as outages occur rather than proactively, hampering efforts to improve reliability for these customers. Considered alternative solutions and identified the appropriate hardening solution for each mainfeeder based on detailed engineering and design.
- Benefits. Improved reliability and resiliency; faster restoration after severe weather events.
- Phase IV Request. Harden a total of 41 mainfeeders in 2027, 2028, and 2029.
- Progress to Date. Completed hardening work on 58 mainfeeders encompassing approximately 351 miles as of December 31, 2025.

b. Targeted Corridor Improvement

Dominion Energy Virginia is implementing several vegetation management programs to improve grid reliability and resiliency while minimizing environmental impacts.

- Need. Improve accessibility to right-of-way; remove risk related to ash trees, hazard trees, and tree overhang.
- Deployment Timeline. Ash tree remediation completed end of 2024; ground floor maintenance/herbicide application to be completed by end of 2026; hazard tree pilot program completed end of 2024; tree overhang pilot program to be completed by 2026.
- Alternatives Considered. Considered addressing ash trees, ground floor growth, and hazard trees reactively rather than proactively, potentially affecting reliability and resiliency, increasing costs for restoration and maintenance work, and requiring higher cost options for ash tree removal. Considered different scopes for pilot programs.
- Benefits. Improved reliability and resiliency; improved access to right-of-way.
- Phase IV Request. Requesting approval to expand the hazard tree pilot system-wide with a targeted phased deployment for a total of 15,000 miles in the 2027-2029 investment years. Additionally requesting to expand the tree overhang pilot on an additional 71 feeders to collect additional data for evaluation of a "ground-to-sky" approach.
- Progress to Date. Removed over 29,400 ash trees, applied over 50,000 miles of herbicide, identified and removed approximately 4,330 hazard trees, and removed approximately 126 miles of tree overhang as of December 31, 2025.

c. Voltage Island Mitigation

Dominion Energy Virginia continues to mitigate voltage islands, which are single substation transformers that serve a population of customers without the support of available load transfer capability within the substation or through field tie switches to adjacent feeders.

- Need. Mitigate risk of an extended outage for customers served by voltage islands if the single substation transformer fails.
- Deployment Timeline. Address 19 voltage islands through completion of the GT Plan.
- Alternatives Considered. Considered not mitigating the risk of extended outages for customers served by voltage islands. Considered alternate solutions and identified the appropriate solution for each voltage island.
- Benefits. Reduced risk of extended outages; improved reliability.
- Phase IV Request. Mitigate four voltage islands in years 2027, 2028, 2029.
- Progress to Date. Addressed eight voltage islands as of December 31, 2025.

d. Stepdown Conversions

Dominion Energy Virginia is proposing to eliminate stepdown transformers by upgrading the line segment to a higher voltage, ultimately increasing reliability and resiliency. This program will proactively mitigate risk of extended outages and expand access to electrification, battery storage, and solar.

- Need. Mitigate risk of an extended outage and expand access to electrification and DERs for customers served by stepdown transformers at a high risk of failure.
- Deployment Timeline. Mitigate 24 stepdown transformers during Phase IV pilot program.
- Alternatives Considered. The Company considered a "do nothing" approach but that approach does not provide the reliability benefits of reducing a point of failure.
- Benefits. Increased reliability; enables additional electrification and DER growth.
- Phase IV Request. Mitigate 24 stepdown transformers.

2. Grid Technologies

Within the category of grid technologies, the Company is: (a) installing intelligent grid devices; (b) deploying FLISR; (c) implementing a DERMS; (d) conducting and publishing hosting capacity analysis; (e) implementing an enterprise asset management system ("EAMS"); (f) installing a new OMS; (g) enabling voltage optimization through infrastructure upgrades; (h) deploying modern technologies at substations; (i) establishing a program to seek energy storage systems as a non-wires alternative solution at identified locations on the distribution grid; (j) demonstrating microgrid capabilities at the Locks Campus; and (k) creating a remote sensing-based Image Management and Analytical Program (iMAP) for its electric distribution organization.

a. Intelligent Grid Devices

Dominion Energy Virginia is continuing to install intelligent grid devices ("IGDs") to provide the data and control necessary to restore power and manage distribution grid voltages and power flows in a system with increasing penetrations of DERs.

- Need. Monitor the distribution grid; remotely control the distribution grid to restore power and address power quality issues created by DERs.
- Deployment Timeline. Deploy IGDs on 685 mainfeeders or feeder segments through completion of the GT Plan.
- Alternatives Considered. Considered different equipment and vendor options to achieve the needed situational awareness and grid control functionality. Considered alternative deployment options in terms of the number and location of devices on each feeder based on detailed engineering and design, and good utility practice.
- Benefits. Increased data about the distribution grid, which enables remote monitoring and control of grid operations; enhanced integrated distribution planning; improved hosting capacity tool; improved reliability.
- Phase IV Request. None.
- Progress to Date. Deployed 137 IGDs on 33 feeders as of December 31, 2025.

b. FLISR

Dominion Energy Virginia is installing a distribution automation system called FLISR, which stands for fault location, isolation, and service restoration, to leverage the capabilities of intelligent grid devices to improve reliability.

- Need. Improve reliability; leverage the full capabilities of intelligent grid devices.
- Deployment Timeline. Upgrades integrated into ADMS by the end of 2024.
- Alternatives Considered. Considered not leveraging the capabilities of IGDs to improve customer reliability through FLISR; rejected alternative because the incremental cost of FLISR software is justified by the reliability improvements for customers. Considered alternative software vendors.
- Benefits. Improved reliability; reduced outage-related O&M expenses; improved customer satisfaction.
- Phase IV Request. None.
- Progress to Date. The Company has successfully implemented the FLISR application as of June 2025 with several of the pilot circuits now operating with FLISR enabled.

c. DER Management System

Dominion Energy Virginia is deploying DERMS to monitor, control, and optimize increasing levels of DERs on the Company's system to maintain a safe and reliable grid.

- Need. Manage increasing volumes of DERs.
- Deployment Timeline. Completed initial installation by 2025; complete additional integrations by 2026.
- Alternatives Considered. Considered using a patchwork of manual processes to manage the increased volumes of DERs of various sizes and types; rejected alternative because of the objectives of FERC Order 2222, the complexity of operating in this manner, and the risk to system reliability and security as penetration increases. Considered alternative software vendors.

- Benefits. Enhanced monitoring and optimization of DERs; enabled customer programs at scale, such as EV managed charging and vehicle-to-grid; facilitated non-wires alternatives; provides support for proposed Virtual Power Plant Pilot Program.
- Phase IV Request. None.
  Progress to Date. The Company has developed a multi-stage deployment plan and a detailed project management plan for deploying the DERMS platform. DERMS went live in Q3 2025 with Stage 1 and Stage 2 capabilities. The Company is continuing to develop and design the specifications for stage three of deployment.

d. Hosting Capacity Analysis

Dominion Energy Virginia completed and published a hosting capacity analysis, refreshing this analysis on a regular basis.

- Need. Provide customers, localities, and developers guidance about which sections of the distribution system may be more suitable to site new DERs.
- Deployment Timeline. Initial hosting capacity tool launched January 2021; additional capabilities implemented in 2022 for smaller generation projects.
- Alternatives Considered. Considered not providing this information to customers and developers, increasing their risk related to siting DERs in terms of costs to interconnect.
- Benefits. Increased information for customers, localities, and developers about how DERs can be placed at each point on the distribution grid without causing voltage or loading problems; increased proliferation of DERs.
- Phase IV Request. None.
- Progress to Date. Launched a utility-scale hosting capacity tool in January 2021 and a behind-the-meter-scale hosting capacity tool in April 2022, available at https://www.dominionenergy.com/projects-and-facilities/electric-projects/energy-grid-transformation/hosting-capacity-tool. Since inception, the tools have accumulated over 36,000 views.

e. Enterprise Asset Management System

Dominion Energy Virginia is implementing EAMS to improve its asset management practices by assessing the health and performance of physical distribution grid assets and to drive predictive maintenance activities.

- Need. Improve asset management practices.
- Deployment Timeline. System deployed in 2024.
- Alternatives Considered. Considered continued use of a patchwork of manual processes and isolated data system to manage distribution grid assets; rejected alternative because it would result in repeated reactive tactics and the inability to develop proactive and predictive strategies to mitigate equipment-related risk and realize asset life optimization opportunities.
- Benefits. Improved capabilities and strategies for managing the procurement, deployment, maintenance, and retirement of distribution equipment and devices.
- Phase IV Request. None.

- Progress to Date. The Company successfully deployed its Enterprise Asset Management System in July 2025.

f. Outage Management System

Dominion Energy Virginia is installing a new OMS to replace an outdated operating system that cannot accommodate the complexity that a modern distribution grid requires.

- Need. Replace outdated operating system; leverage the full benefits of other GT Plan investments; modernize customer engagement.
- Deployment Timeline. Complete deployment by the end of 2026.
- Alternatives Considered. Considered alternatives related to the timing of installation. Considered alternative vendors.
- Benefits. Restoration efficiency and productivity; improved customer experience.
- Phase IV Request. None.
- Progress to Date. The underlying software and hardware infrastructure for OMS has been installed. OMS integration and configuration activities occurred in 2025 and will continue through 2026. Final performance and integration testing is scheduled to be conducted in 2026, with an implementation date targeted by the end of 2026.

g. Voltage Optimization Enablement

Dominion Energy Virginia is making the improvements necessary to enable voltage optimization on the feeders where AMI has been installed.

- Need. Enable voltage optimization to achieve energy savings for customers by performing the necessary infrastructure improvements, as identified by data from AMI.
- Deployment Timeline. Complete infrastructure improvements that support implementing a 1% energy savings through voltage optimization capability, estimated at approximately 126,000 customer premises to be addressed.
- Alternatives Considered. Considered lesser percentage voltage reductions to target, which affects the necessary infrastructure improvements and resulting energy savings.
- Benefits. Broadly enabled voltage optimization, which will result in generally lower voltage control settings leading to lower energy consumption for most customers without a noticeable difference in service level.
- Phase IV Request. Complete improvements affecting approximately 43,000 customer premises.
- Progress to Date. As of December 31, 2025, 20,446 customer premises have been improved as a part of the VO program.

h. Substation Technology Deployment

Dominion Energy Virginia continues to modernize certain distribution substations by upgrading electromechanical relays; deploying substation communication protocol and power quality monitoring equipment; and piloting advanced substation technology.

- Need. Integrate DERs; improve reliability, power quality, and safety; study advanced substation technology.
- Deployment Timeline. Modernize 44 substations through completion of the GT Plan; deploy advanced substation technology as appropriate based on outcome of pilots.
- Alternatives Considered. Considered addressing substation equipment issues reactively rather than proactively; rejected alternative because it could result in an inability to effectively integrate DERs or feeder automation, such as FLISR, on the associated feeders.
- Benefits. Support for the integration of DERs while maintaining voltage stability; improved reliability, power quality, and resilience of the distribution grid; improved visibility and control; enhanced understanding of advanced substation technology.
- Phase IV Request. None.
- Progress to Date. Two Phase II substations have been completed, two are in construction, and one is in the permitting process. Two Phase III substations are complete and the remaining 18 are in various stages of construction, engineering and design. The Company has completed installation of all 200 power quality monitors and has completed the Fault Analysis and Lightning Location System (FALLS), Synchrophasor (Phasor Measurement Units), and IEC61850 pilots.

i. NWA Pilot Program

Dominion Energy Virginia has begun implementing a non-wires alternative pilot to identify opportunities in which a traditional infrastructure investment may be deferred or avoided by investing in an alternative solution, with initial focus on energy storage systems.

- Need. Gain experience with integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with NWAs. Address requirement from the VCEA related to the deployment of energy storage.
- Deployment Timeline. First RFP for NWA solutions issued in 2025.
- Alternatives Considered. Considered alternative timelines for implementing NWA Program. Considered seeking NWA solutions in addition to energy storage.
- Benefits. Address VCEA requirement that the deployment of energy storage involved non-wires alternatives program; experience with NWAs; potential deployment of energy storage to meet VCEA development targets, and associated experience with energy storage; potential deferment of traditional capital investments.
- Phase IV Request. None.
- Progress to Date. Several key milestones for the implementation of the NWA program have been completed since approval of the program. Specifically, the software that will be utilized to evaluate potential projects for technical and economic viability to be an NWA project has been procured, configured, and installed. In addition, training on NWA project identification has been completed within the planning organization. Reporting has been finalized to provide data on projects evaluated for the program.

j. Locks Campus Microgrid

Dominion Energy Virginia is studying a new technology—microgrids—by installing one at its Locks Campus near Petersburg, Virginia.

- Need. Obtain experience with microgrids.
- Deployment Timeline. Construction targeted for completion in 2026
- Alternatives Considered. Not obtaining experience with microgrids.
- Benefits. Enhanced understanding of microgrids from real-world data and testing of DER grid support and islanding capabilities.
- Phase IV Request. None.
  Progress to Date. Construction on the microgrid continues to progress. The building construction is complete with reinforcement and racking installed. Additionally, the Company's risk engineering team along with the battery vendor have successfully performed factory testing and delivered the battery storage system.

k. Remote sensing based Image Management and Analytical Program (iMAP)

The Company is implementing a remote sensing-based image management and analytical program (iMAP) for its electric distribution organization.

- Need. Provide the Company with more information about the current state of its assets.
- Deployment Timeline. The foundational image data management platform and technology pilots will be implemented and deployed over a 12-month period; implementation commenced in 2025, following Commission approval in the Phase III B proceeding.
- Alternatives Considered. The Company considered third-party managed solutions, but those solutions are costly and potentially introduce data, security, and enterprise integration issues.
- Benefits. Enable more efficient and proactive maintenance, while helping to prevent and reduce the duration of outages; information can also support more accurate engineering analyses, such as pole loading analyses.
- Phase IV Request - None
- Progress to Date.
  - Foundational Image Data Management Platform – Implementation of the platform is ongoing and on track for a Fall 2026 production release.
  - Technology pilots - The approved technology pilots are progressing on schedule. Remote sensed data collection to support the technology pilots is complete, and analysis and field validation are ongoing.

3. Security

Dominion Energy Virginia will continue to protect the distribution grid by providing adequate and cost-effective security control measures to manage the growing threat to the energy sector and to protect from cyber and physical attacks.

a. Physical Security

The Company plans to enhance physical security at key distribution substations.

- Need. Protect the distribution grid from security threats, thus protecting the Company and

its customers.

- Deployment Timeline. Enhance physical security at 45 substations through completion of the GT Plan.
- Alternatives Considered. Considered not enhancing physical security at critical distribution substations; rejected alternative because it would leave these substations vulnerable to threats.
- Benefits. Improved detection, monitoring, and response time to potential security threats.
- Phase IV Request. None.
- Progress to Date. Enhanced physical security at eleven critical substations as of December 31, 2025.

b. Cyber Security

The Company plans to protect the investments proposed in the Grid Transformation Plan through the necessary cyber security investments.

- Need. Protect the distribution grid from security threats, thus protecting the Company and its customers.
- Deployment Timeline. As needed to protect other approved grid transformation projects.
- Alternatives Considered. Considered cyber security solutions as needed based on the security needs of the specific project, leveraging existing solutions where possible.
- Benefits. Avoided attacks on the system; mitigated risk of new or emerging threats.
- Phase IV Request. None.
- Progress to Date. Leveraged existing agreements and solutions, requiring limited cyber security improvements to support other GT Plan projects.

4. Telecommunications

Dominion Energy Virginia proposes to continue to deploy a comprehensive telecommunications strategy requiring multiple components specifically designed and deployed as an integrated solution to meet the wide range needs of a transformed distribution grid. The strategy includes Tier 1, a high-speed broadband with very low latency network with redundancy; and Tier 2, a broadband network with redundancy, as well as increasing the capacity of the Company's network operations center ("NOC"). This strategy also includes upgrading identified telecommunication sites and replacing network infrastructure within identified substations.

- Need. Enable the secure communication required for a transformed grid. Enhance security, reliability, and resiliency of data transport.
- Deployment Timeline. Tier 1 by 2021; Tier 2 deployed through completion of the GT Plan; NOC capacity increases through completion of the GT Plan; telecommunication site upgrades by 2026; substation network upgrades by completion of the GT Plan.
- Alternatives Considered. Prior to Phase I, various alternatives considered to address the wide range of business and technical requirements. Now that deployment of Tier 1 is complete and Tier 2 is underway, no alternatives considered.
- Benefits. Secure, reliable, and resilient telecommunications infrastructure; enabled grid transformation projects that require real-time communications for situational awareness and

grid control.

- Phase IV Request. Proposing to continue its telecom deployment of the Tier 2 network. Specifically, the Company proposes to extend high-speed connectivity and MPLS to an additional 38 critical facilities through Company-owned fiber.
- Progress to Date. Completed Tier 1 implementation. Deployed Tier 2 telecommunications solutions to over 244 facilities, including installing 555 miles of fiber.

5. Customer Education

Dominion Energy Virginia plans to improve the customer experience by incorporating education into various Plan components and including general energy education. While this customer education plan focuses on enhanced capabilities enabled by GT Plan, it supplements the Company's overall efforts to educate its customers on topics ranging from available rate schedules to general energy education.

- Need. Provide customers with concise, consistent, and easy-to-understand educational content.
- Deployment Timeline. As needed to support other approved grid transformation projects.
- Alternatives Considered. Considered various communication channels based on the educational need.
- Benefits. Improved customer experience; enhanced understanding of GT Plan and related benefits.
- Phase IV Request. None.
- Progress to Date. Developed and published concise, consistent, and easy-to-understand content via multiple external communications channels.

B. Alignment with Customer and Stakeholder Feedback

As discussed in Section III.B, the Company received customer feedback on a range of priorities associated with the Grid Transformation Plan as part of the 2023 Maslansky Survey. Figure 4 notes the top findings on what customers rank with highest importance.

Figure 4: Customer Feedback Priorities

	Customer Priorities
1	Completes work without needing follow-up
2	Responds quickly to replace faulty equipment
3	Completes scheduled work when they say they will
4	Protects equipment from hazards and wear-and-tear that can result in unexpected outages
5	Invests in advanced technologies that help prevent outages or reduce their duration
6	Adapts effectively in the event of disruptions or crises
7	Has an outage map that includes accurate estimates of outage time and progress in restoring power
8	Invests in technology that helps prevent outages and respond to them faster when they occur
9	Increases energy availability by identifying the ideal locations for new facilities
10	Allows me to set custom alerts so I can choose which notifications I want to receive and how I want to receive them

As shown in Figure 4, among attributes tested, those relating to outage response and prevention rise to the top as priority areas of focus. These findings support the proposed GT Plan investments and make clear that they will provide the types of benefits the Company's customers value most—enhanced reliability and accurate information.

As discussed in Section III.C, the Company initiated a series of stakeholder sessions in 2019 to inform and develop goals for a modern grid and the customer experience. Through the 2019 GT Plan stakeholder process, four goals were identified: (i) enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access (Optionality); (ii) evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles (Sustainability); (iii) build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management (Resiliency); and (iv) deliver value for customers by optimizing demand and seeking to reduce system and customer costs (Affordability). GT Plan projects directly support each of these four goals, through deployment of technology to empower customers to make informed decisions about their energy usage, enabling increased adoption of DERs in a responsible manner, and delivering better reliability and fewer outages for customers.

C. Costs

The Company estimated costs for grid transformation projects using competitively-negotiated contracts and responses to competitive requests for proposals ("RFPs") and requests for information ("RFIs"), informed by prior experience. The Company's filing provides detailed information used to determine costs and includes the relevant contracts or summaries of the completed RFPs and RFIs.

In Phase I of the Grid Transformation Plan, the Company suggested, and the Commission approved, a maximum amount of investment—by project for capital investment and operation and maintenance expenses—deemed reasonable and prudent ("cost caps"). Should costs exceed the approved cost caps, those costs would be incurred at the Company's risk, and it would be the Company's burden to demonstrate reasonableness and prudence for any such incremental investment. The respective program costs caps can be found in Schedule 1 of the Grid Transformation Plan Annual Report.

Initially the Company received approval to recover costs related to the approved projects through Rider GT, which has more recently been approved for consolidation and cost recovery in the Rider DIST rate adjustment clause ("RAC"). As to Phase IIIB and future phases of projects in the Plan, the Company has not yet determined its plans for cost recovery but anticipates cost recovery will occur through Rider DIST.

D. Benefits

The overarching benefits of the Grid Transformation Plan are that it facilitates the integration of DERs and enhances distribution grid reliability and security. All proposed projects contribute to these core objectives in some way.

The Company engaged a third-party industry expert, West Monroe Partners, to generate a cost-benefit analysis ("CBA") model for the Grid Transformation Plan that quantifies the benefits of the comprehensive GT Plan compared to the costs. Figure 5 presents the results of the CBA.

Figure 5: CBA Summary

GT Plan Cost-Benefit Model Summary

(Revenue Requirement Basis, $ in Millions)

BENEFITS & COSTS	NOMINAL	PV[1]
Grid Infrastructure Mainfeeder Hardening, Targeted Corridor Improvement, Voltage Island Mitigation, and Stepdown Conversion Pilot		
BENEFITS[2] *(Asset Life)*:	**$10,898.2**	**$2,662.5**
Avoided/Deferred Capital	$33.2	$7.9
O&M Savings	$65.5	$19.2
Enhanced Reliability	$10,799.5	$2,635.4
COSTS *(Revenue Requirement)*:	**$4,199.5**	**$1,704.9**
Net Benefit (Cost):	**$6,698.7**	**$957.6**
Benefit/Cost Ratio:	**2.6**	**1.56**
Grid Technologies Intelligent Grid Devices, FLISR Software, OMS, DERMS, Hosting Capacity, EAMS, VO Enablement, Substation Technology Deployment, NWA Program, iMAP and Locks Campus Microgrid		
BENEFITS[2] *(Asset Life)*:	**$18,190.6**	**$3,802.5**
Avoided/Deferred Capital	$942.7	$174.4
O&M Savings	$134.7	$87.3
Energy & Demand Savings	$6,488.8	$1,361.9
Enhanced Reliability	$10,622.6	$2,177.8
Reduction of Bad Debt & Energy Diversion	$1.8	$1.1
COSTS *(Revenue Requirement)*:	**$6,866.0**	**$2,463.1**
Net Benefit (Cost):	**$11,324.6**	**$1,339.5**
Benefit/Cost Ratio:	**2.6**	**1.5**
GT Plan Total[3]		
Total Net Benefit (Cost):	**$16,910.0**	**$1,812.1**
Total Benefit/Cost Ratio:	**2.4**	**1.38**

[1] *Present Value (PV) calculated using Weighted Average Cost of Capital (WACC) of 7.36%*

[2] *O&M Savings, Energy & Demand Savings, Enhanced Reliability, and Reduction of Bad Debt & Energy Diversion are stated on a Cash Flow Basis*

[3] *GT Plan Total includes costs and benefits associated with Telecom, Customer Education, Physical Security, and Cyber Security costs not tied to*

As can be seen, the CBA model represents a positive business case from a financial perspective, providing over $1.8 billion in net benefits to customers on a net present value basis, with a benefit to cost ratio of 1.38. Additional quantitative benefits include reduced greenhouse gas emissions and positive economic development impacts. Some of the benefits derive from programs and offerings that the Company has implemented after projects were deployed.

The CBA model focuses on quantifiable benefits, but the Grid Transformation Plan produces other qualitative, non-quantifiable benefits. For example, there are benefits that are difficult to quantify, like avoiding a cyberattack; providing resilient service to military bases, hospitals and communities; and providing customers with accurate and timely information that has implications for their daily lives.

The following sections highlight certain GT Plan benefits important to the Company and various stakeholders.

1. Time-varying Rates

Transformational investments in AMI and the CIP, when coupled with customer education and communication, enable the Company to broadly offer time-varying rates. Time-varying rates provide incentives for customers to shift their usage to off-peak periods when the cost of generating electricity is less expensive, which both reduces the demand on the Company's system and reduces the customers' bills. The Company has a concrete, definitive plan to implement time-varying rates on a system-wide basis—both a time-of-use rate and a peak-time rebate ("PTR") program. The Company launched its Off-Peak Plan—Schedule 1G—in January 2021. Schedule 1G was available to the first 10,000 customers who enrolled. While the Company estimated it would take four years to reach the enrollment cap, Schedule 1G reached 10,000 participants in less than one year on January 4, 2022. The Company requested and received approval of the expansion of Schedule 1G to additional customers up to 20,000 participants. As approved in the Company's most recent biennial review, Case No. PUR-2025-00058, all customers with smart meters are now able to enroll in Schedule 1G. In August 2023, the Commission approved a system-wide opt-in PTR program in its DSM proceeding, Case No. PUR-2022-00210.

2. Demand-side Management Initiatives

The foundational and transformational investments of the Grid Transformation Plan enable enhanced and targeted DSM initiatives in many ways. Investment in the full deployment of AMI and the CIP enables the Company to broadly offer enhanced demand response programs—such as time-varying rates, PTR, and managed charging for EVs—and to deploy new energy efficiency programs—such as voltage optimization. Additionally, the interval usage data captured by AMI enhances existing DSM programs and improves evaluation, measurement, and verification ("EM&V") of DSM programs. Finally, the deployment of DERMS provides the capability to manage demand response programs going forward. All these programs and enhancements should lead to savings for the individual customers who participate in the various DSM programs but should also lead to system energy and demand savings that will benefit all customers. For example, voltage optimization utilizes the data collected from AMI and other intelligent grid devices to

reduce the voltage supplied to customers to the optimum level, which results in lower energy consumption for most customers without a noticeable difference in service level.

3. Integrated Distribution Planning

As described in Section II, the fundamental changes in the energy industry have driven not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs. The real-time data from AMI and intelligent grid devices, paired with automated control systems (*e.g.*, DERMS) and advanced planning tools have and will continue to be foundational to the transition to integrated distribution planning.

4. Reliability

Transformational investments in grid infrastructure and grid technologies improve reliability for customers across the Company's service territory. While some projects, like mainfeeder hardening and voltage island mitigation, focus on targeted populations of customers, others will be deployed more broadly, such as targeted corridor improvement. The CBA model quantifies reliability benefits using the Department of Energy's Interruption Cost Estimate Calculator ("ICE Calculator"), a recognized method for determining the economic value of increased reliability. This tool has been updated multiple times over the past decade to improve the accuracy of the results, and the Company fully supports the quantified benefits presented. Additionally, Dominion Energy Virginia engaged with Lawrence Berkeley National Laboratory in 2020 on a multi-year project to refine the ICE Calculator and incorporate Virginia-specific data. Since 2020, updates to reliability survey questionnaires for residential and non-residential customers has been completed based on feedback provided by the Company and others involved in the initiative. In December 2022, a successful pre-test of the residential survey was conducted with a sample of Company customers. The survey of Company customers began in the first half of 2023 and was completed in early 2024. ICE 2.0 was made available in April 2025. The Phase IV CBA incorporates ICE version 2.2, which was released on February 19, 2026, and is the only web-based ICE calculator currently available

5. Load Forecasting

The data obtained from AMI can also enhance the Company's load forecasting process. AMI data will permit the Company to examine consumption patterns on an hourly basis. This data can then be used to create consumption forecast models for various customer segment levels, for example, residential heating system type, electrification impacts, demand response and energy efficiency effects, and DER adoption. These feeder level forecasts can then be rolled up to a system level and compared against the Company's current forecasting methods.

6. Broadband Program

In addition to supporting grid transformation objectives, the foundational telecommunications investments proposed as part of the GT Plan also provide the opportunity to support expanded deployment of broadband in the Commonwealth through the Rural Broadband Program. The telecommunications project includes the extension of the Company's fiber network to substations and key facilities. The expansion of the Company's fiber network, particularly in rural unserved areas, provides opportunities to leverage the fiber network for the benefit of middle-mile expansion in unserved and underserved markets as a part of the Company's Rural Broadband Program. Not only does the fiber serve Dominion Energy Virginia's connectivity needs at key facilities, but it also supports existing and potential internet service providers' use of the fiber capacity to improve availability of broadband for commercial, government, institutional, and residential customers in unserved areas of Virginia. The Commission has approved rural broadband projects in Surry County; Botetourt County; Louisa, Appomattox, Albemarle, Buckingham, Cumberland, Fluvanna, Goochland, Nelson, and Powhatan Counties; Augusta, Clarke, Fauquier, and Rockingham Counties; Brunswick, Greenville, Halifax, and Mecklenburg Counties; Sussex, Culpeper, Hanover, Loudoun, and Middlesex Counties; and in the Northern Neck region of Virginia.

F. Regulatory Process

The GTSA mandated that the Company petition the Commission for approval of a plan for electric distribution grid transformation projects. The GTSA also set forth the applicable standard for reviewing such petitions:

> In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d.[8]

The Commission must rule on any petition not more than six months after the date of filing.

To date, the Company has submitted five petitions for prudence determinations related to Phases I–IIIB of its Grid Transformation Plan since 2018. In each case, the Commission issued a final order within several months of filing, with the most recent being the 2025 Final Order for Phase IIIB.

[8] Va. Code § 56-585.1 A 6.

GT Plan Phase	Filing Date	Case No.	Commission Final Order
Phase I	July 2018	PUR-2018-00100	Jan. 17, 2019
Phase IB	Sept. 2019	PUR-2019-00154	Mar. 26, 2020 (Final) / Apr. 27, 2020 (Reconsideration)
Phase II	June 2021	PUR-2021-00127	Jan. 7, 2022
Phase III	Mar. 2023	PUR-2023-00051	Sept. 18, 2023
Phase IIIB	Mar. 2025	PUR-2025-00051	Sept. 23, 2025

Separately, the Company has filed five cost-recovery petitions for Rider GT (and now Rider DIST). Four have received final orders (2021, 2022, 2023, 2024), and the 2025 RIDER DIST proceedings final order is still pending, expected to be received in May 2026.

Rider Filing	Filing Date	Case No.	Commission Final Order
Rider GT – Initial	Aug. 2021	PUR-2021-00083	May 13, 2022
Rider GT – Update	Aug. 2022	PUR-2022-00140	Apr. 27, 2023
Rider GT – Update	Aug. 2023	PUR-2023-00136	May 1, 2024
Rider DIST	Aug. 2024	PUR-2024-00137	May 1, 2025
Rider DIST	Aug. 2025	PUR-2025-00136	Pending

In the 2019 Final Order, the Commission ordered the Company to file an annual report on or before March 31, 2021, and each year thereafter, to include reporting metrics proposed by the Company and other information directed by the Commission. In its 2021 Final Order, the Commission added additional requirements for the annual report. The Company filed its first annual report on March 31, 2021, in the docket for Case No. PUR-2020-00154. The Company filed its second annual report on March 31, 2022, in the docket for Case Nos. PUR-2020-00154 and PUR-2021-00127. The Company filed its third annual report on March 31, 2023. The Company filed its fourth annual report on March 29, 2024, and its fifth annual report on March 24, 2025. The sixth annual report is being filed on March 31, 2026. The Company will

incorporate additional metrics and information into its annual reports for any additional projects approved as part of Phase IV.

LIST OF ACRONYMS

Acronym	Meaning
ADMS	Advanced distribution management system
AMI	Advanced metering infrastructure
AMR	Automated meter reading
BEA RIMS	Bureau of Economic Analysis Regional Input-Output Modeling System
BESS	Battery energy storage system
BTM	Behind-the-meter
CAIDI	Customer average interruption duration index
CBA	Cost-benefit analysis
CBMS	Customer Business Management System
C&I	Commercial and industrial
CI	Customer interruptions
CIP	Customer information platform
CIS	Customer information system
CMI	Customer minutes of interruption
COBOL	Common business-oriented language
DA	Distribution automation
DAS	Data analytics system
DCFC	Direct current fast charging
DERs	Distributed energy resources
DERMS	Distributed energy resource management system
DOE	Department of Energy
DR	Demand response
DSM	Demand-side management
EAB	Emerald ash borer
EAMS	Enterprise asset management system
EE	Energy efficiency
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EM&V	Evaluation, measurement, and verification
EPA	Environmental Protection Agency
EV	Electric vehicle
FAN	Field area network
FERC	Federal Energy Regulatory Commission
FLISR	Fault location, isolation and service restoration
GHG	Greenhouse gas
GIS	Geographic information system
GT Plan	Grid Transformation Plan
GTSA	Grid Transformation and Security Act of 2018
ICE Calculator	DOE's Interruption Cost Estimate Calculator
IDP	Integrated distribution planning
IEEE	Institute of Electrical and Electronics Engineers

Acronym	Meaning
IGDs	Intelligent grid devices
iMAP	Image Management and Analytics Program
INSI	Itron Networked Solutions, Inc.
IT	Information technology
kV	Kilovolt
kWh	Kilowatt-hour
LTC	Load tap changer
MDMS	Meter data management system
MPLS	Multi-protocol label switching
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Officials
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NIC	Network interface card
NIST	National Institute of Standards and Technology
NOC	Network Operations Center
NPV	Net present value
NREL	National Renewable Energy Laboratory
NWA	Non-wires alternatives
O&M	Operations and maintenance
OMS	Outage management system
OT	Operational technology
Phase I	Grid transformation projects for 2019, 2020, and 2021 approved in Case Nos. PUR-2018-00100 and PUR-2019-00154
Phase IA	Phase I projects approved in Case No. PUR-2018-00100
Phase IB	Phase I projects approved in Case No. PUR-2019-00154
Phase II	Grid transformation projects for 2022 and 2023 approved in Case No. PUR-2021-00127
Phase III	Grid transformation projects for 2024, 2025, and 2026 approved in Case No. PUR-2023-00051
Phase IIIB	Grid transformation projects approved for 2024, 2025, and 2026 in Case No. PUR-2025-00051
Phase IV	Grid Transformation projects proposed for 2027-2029
PII	Personal-identifying information
PTR	Peak-time rebate
RAC	Rate adjustment clause
RFI	Request for information
RFP	Request for proposals
RPS	Renewable energy portfolio standard
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition

Acronym	Meaning
SCIP Program	Smart Charging Infrastructure Pilot Program
SONET	Synchronous optical networking
STATCOMs	Static compensators
SUP	Strategic Undergrounding Program
T&D	Transmission and distribution
TOU	Time-of-use
V	Volt
Va. Code	Code of Virginia
VCEA	Virginia Clean Economy Act of 2020
VEJA	Virginia Environmental Justice Act
VO	Voltage optimization

GLOSSARY

ADMS (advanced distribution management system): A software platform that supports and manages the full suite of distribution grid management and optimization technologies employed by the Company.

AMI (advanced metering infrastructure): An over-arching metering system, which includes smart meters, a field area network, and a back office system called the AMI head-end system.

AMI head-end system: A back office system that receives and processes the data for smart meters, and serves as an operating platform for the back office team responsible for operating and maintaining AMI. The AMI head-end system also provides information from smart meters to other Company operating and analytical systems.

AMR (automated meter reading): A technology that records usage data and transmits it to the Company one-way. The Company reads these meters through drive-by readings using specially equipped trucks that receive the data through radio signals.

Automated control systems: Technology that allows for near real-time adjustment of the grid to changing energy loads, distributed generation, or feeder fault conditions without or with limited operator intervention.

Backfeed: The flow of electric power from the distribution grid to the transmission grid. Also represents the flow of electric power from a net metering distributed energy resource to the distribution grid during periods where distributed generation exceeds consumption at the premises.

Backhaul network: The backhaul portion of the network comprises the intermediate links between the core network and the small subnetworks at the edge of the network.

Base rates: The Company's existing rates for generation and distribution services.

BESS (battery energy storage system): A type of energy storage that stores energy for later discharge to the electrical grid.

CBMS (customer business management system): The core system delivering business functions such as customer service, account management, credit and collections, service orders, meter inventory, usage, billing, service address management, portfolio management, rates and financial based activities.

CIP (customer information platform): A combination of technologies, applications, and projects at the core of the customer experience, consisting primarily of the CIS, MDMS, customer portals, and other customer experience applications.

CIS (Customer Information System): Another term for CBMS.

Collector: A device deployed as a component of AMI designed to enable two-way communications to and from meters within range of the device. The device captures meter data and transmits via a dedicated backhaul communications network to the AMI head-end system to drive business processes.

Cyber security: Programs, techniques, and technology to protect the networks, devices, and programs from cyberattack.

DCFC (direct current fast charging): Electric vehicle charging technology capable of charging batteries to a 60 to 80 mile range state of charge within 20 minutes.

Decentralization: A concept that involves moving the electric grid away from relying solely on large centralized generating plants that supply power via the transmission grid to the distribution grid and ultimately end users, to a power grid where large generating plants and smaller distributed energy resources supply the grid simultaneously from two directions: the large generators through transmission lines and the smaller resources supplying from the distribution grid.

DER (distributed energy resource): A broad term used to describe resources connected to the distribution system, many of which are generation resources using renewable energy, such as solar and wind. DERs can also include, but are not limited to, energy storage, EVs, and demand response assets.

DERMS (distributed energy resource management system): A system that monitors and analyzes performance and status data from multiple distributed energy resources and has the ability to control those resources to maintain safety and reliability on the energy grid while maximizing benefits of the resources.

Distribution grid: The portion of the electrical utility system that delivers electrical power from the transmission grid through a substation transformer to end-use customers; typical distribution grid operating voltages range from 4 kV to 46 kV.

DSM (demand-side management): Activities that are designed to modify the level and pattern of electricity usage. DSM efforts in the Commonwealth focus primarily on two methods to manage demand: (i) energy efficiency and conservation, which aims to reduce the total amount of electricity used; and (ii) demand response (often peak shaving), which aims to shift the time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices on the electric grid.

EAMS (enterprise asset management system): A system that aggregates data and attributes of grid assets and provides capabilities to manage grid assets at all points in their life cycle, including procurement, deployment, and retirement. The system allows for collection of information related to the health and performance of grid components and analysis to drive life cycle decision making.

EM&V (evaluation, measurement, and verification): The collection of methods and processes used to assess the performance of demand-side management activities so that planned results can be achieved with greater certainty and future activities can be more effective.

Fault: An abnormal electrical condition caused by a short circuit on a feeder section.

Feeder: An electric distribution subsystem that begins at a substation and distributes electrical power within a localized service area. Feeders are comprised of mainfeeders, tap lines, and service lines.

FLISR (fault location, isolation, and service restoration): A distribution network system that works with intelligent grid devices such as switches, reclosers, line sensors, and a secure communications network to automatically isolate faulted feeder sections and reroute power to restore most customers in a matter of seconds or minutes.

GIS (geographic information system): A system designed to capture, store, analyze, and present spatial or geographic data, herein referring to distribution grid assets.

Grid hardening: Physical grid improvements that improve reliability and resiliency by rebuilding portions of the grid to eliminate outages and reduce damage for faster restoration.

Grid modernization: A broad term used to describe efforts to improve and modernize the grid.

Grid transformation: A broad term used to describe efforts to improve and modernize the grid.

Hosting capacity: The estimated amount of DERs that can be connected to each segment of the distribution grid without causing voltage or loading issues as determined by engineering analysis.

IGDs (intelligent grid devices): Various devices that provide situational awareness and control capability of the grid and enable two-way communication and centralized control of the power system.

iMAP (Remote Sensing-Based, Image Management and Analytics Program): A foundational, Company-managed cloud-based system used to centrally store, manage, and analyze remotely sensed data.

Integrated distribution planning: A consolidated process to address the capacity, performance, reliability, resilience, and DER integration needs of the distribution grid integration needs of the distribution grid.

Intermittent generation: Generation resources that do not produce continuously available electricity due to external factors that cannot be controlled, such as solar and wind power. The power from such resources is non-dispatchable, meaning that it cannot be called upon at all times, only at times when the conditions for their power are present (*e.g.*, sun or wind) and the amount of power varies depending on those conditions.

Kilovolt (kV): Unit of measure for electric equipment and facilities representing 1,000 volts.

Latency: The amount of time it takes for a packet of data to get from one designated point to another through telecommunications networks.

Mainfeeder: The three phase sections of a feeder that distribute electrical power from substations to tap lines and individual customers.

MDMS (meter data management system): A system that processes and stores interval data used for billing, and calculates billable consumption for interval meter data.

Mesh network: The information network created from smart meters communicating with each other.

Microgrid: A group of interconnected loads and DERs that act as a small power grid, able to operate when connected to the larger distribution grid and also able to continue to operate as an "island" when there is an interruption or other grid disturbance that affects normal power flow from the grid.

Microgrid controller: A device that enables the establishment of a microgrid by controlling distributed energy resources and loads in a predetermined electrical system to maintain acceptable frequency and voltage while the microgrid is disconnected from the distribution grid.

MPLS (multi-protocol label switching): A mechanism for the routing of communications within a network as data travels across network nodes.

One-way energy: Power flow from a centralized location, such as a substation, along a distribution feeder, to end users.

OMS (outage management system): A centralized software solution and associated infrastructure for the purpose of analyzing and managing outage events on the distribution system. It uses field information and notifications from customers to identify outage events, create and manage restoration work requests, and provide restoration information to customers.

PTR (peak-time rebate) programs: Programs that provide incentive rewards for customers who achieve a desired reduction in usage during specific timeframes on abnormally hot or cold days.

Physical security: The protection of people, property, and physical assets from actions and events that could cause damage or loss.

Redundancy: In telecommunications, a process through which additional or alternate instances of network devices, equipment, and communication mediums are installed within network infrastructure. It is a method for ensuring network availability in case of a network device or path failure and unavailability.

Reliability: The ability of the distribution system to deliver uninterrupted power service to customers.

Repeater: An electronic device that receives a signal and retransmits it. Repeaters are used to extend transmissions so that the signal can cover longer distances or be received on the other side of an obstruction.

Resiliency: The ability of the power grid to withstand outages and maintain service to customers and recover from outages to restore service to customers.

RFI (request for information): A business process whose purpose is to collect written information about the capabilities of various suppliers.

RFP (request for proposals): A competitive bidding process where vendors and contractors offer to provide a service, asset, or good for a certain cost.

SCADA (supervisory control and data acquisition): A computer system that monitors and provides control of distribution assets, primarily located at substations.

Security information event and management (SIEM): A system to provide analysis of collected security events and logs to identify and detect potential security incidents as well as support incident response.

Single-phase: A segment of a power system consisting of one primary voltage conductor and one neutral conductor.

Situational awareness: Real-time perception of the grid and its environment that allows operators to project future outcomes as well as deal with present events.

Smart inverter: Inverters have the basic inverter function of converting direct current to alternating current, but also have additional capabilities such as voltage regulation, frequency support, and ride through capabilities (*i.e.*, staying online during grid events).

Smart meter: Electric meters that digitally gather energy usage data in specified increments (*i.e.*, interval data) and other related information as part of an AMI system.

Three-phase: A segment of a power system consisting of three primary voltage conductors and one neutral conductor.

Time-of-use rates: Rates that have pre-defined periods with tiered energy pricing that are generally aligned with the actual cost of producing electricity during those periods

Time-varying rates: Rates that provide incentives for customers to shift their usage to off-peak periods when the cost of generating electricity is less expensive, which both reduces the demand on the Company's system and can reduce the customers' bills.

Transmission grid: The high voltage part of the electrical grid that carries bulk power directly from large generating facilities to the distribution grid. Typical transmission grid operating voltages range from 69 kV to 500 kV.

Visibility: Real-time awareness of the grid's operating conditions.

Voltage optimization: The more precise control of distribution grid voltage that is possible with information from smart meters and a voltage control system.

Voltage island: A single substation transformer that serves a population of customers without the support of available load transfer capability within the substation or adjacent feeders. If a single transformer fails, all customers served by the substation could face an extended outage.

APPENDIX A: Existing Distribution Grid

Existing Distribution Grid

As discussed in Section I.A of the Plan Document, the electric grid was originally designed for one-way flow of electricity to meet customers' demand—from the generator, through the transmission system, to the distribution system and the end-use customer. In the traditional distribution system design, electricity typically flows from a substation, through mainfeeders, to tap lines and then service lines that are connected to the end-use customer.

Dominion Energy Virginia's over 2.7 million customer accounts in the Commonwealth power the business economy and serve over 5 million residents. The Company's existing distribution system in Virginia consists of more than 53,000 miles of overhead and underground cable, and over 400 substations. The distribution system utilizes a variety of devices for functions from voltage control to power flow management, and relies on multiple operating systems for various functions from customer billing to outage management. The following sections provide a detailed description of the Company's existing distribution system.

A. Substations

The primary function of a distribution substation is to transfer power from the higher voltage system, which typically ranges from 35 kV to 230 kV on the Company's system, to the lower voltage system, which typically ranges from 4 kV to 35 kV. Once this power is "stepped down," it is placed on the distribution system for delivery to the end use customer.

There are many pieces of equipment and devices that help to facilitate this transfer of power, including the following:

Substation transformers. Equipment that handles the "stepping down" of higher voltages to lower voltages.

Substation bus. Metal tubes or bars that carry electric current from the substation transformer to other devices, such as circuit breakers, or from the other devices to the substation transformer.

Substation circuit breakers. Devices that enable the flow of power into and out of the substation and serve to isolate faults.

Voltage regulation devices. Devices that help keep voltage within the desired bandwidth.

Communication schemes and protocols. Communication hardware and software responsible for transferring data and signals from various devices within the substation, as well as between the substation and the operating center or engineers and technicians.

Relays. Decision-making devices that control the operation of various high voltage equipment such as circuit breakers.

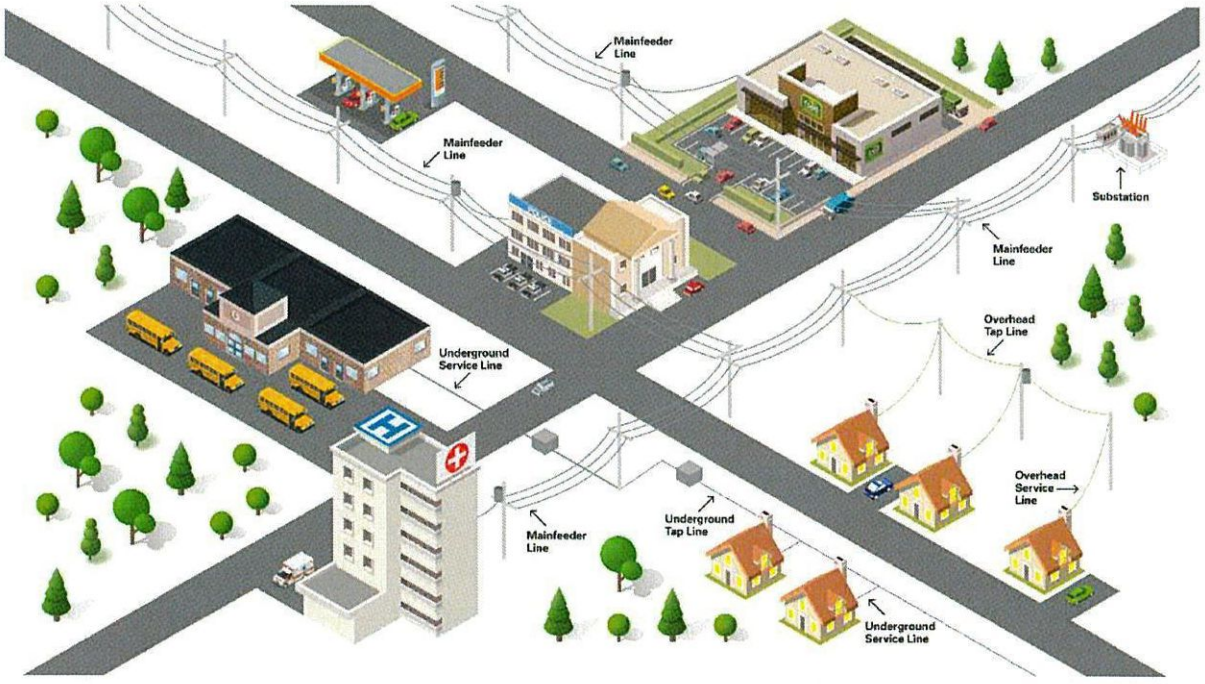
Electrical sensors. Devices responsible for providing electrical signals and inputs into the relays.

Control house. Enclosure that houses relays, communication hardware, back-up batteries, and other low voltage devices.

B. Wires

Within the distribution system, the wires—also known as conductors—transmit electricity from substations to end-use customers. A system of conductors is referred to as either a circuit or a feeder. The Company will generally use the term "feeder" in this proceeding. The Company operates approximately 1,900 feeders in Virginia. There are three parts to feeders, the mainfeeders, the tap lines, and the service lines.

Distribution System Illustration



1. Mainfeeders

Mainfeeders are the three-phase portion of the distribution system that carries electricity from substations to tap lines and end-use customers. Larger customers, such as certain businesses and public services, are often served directly from the mainfeeders. Mainfeeders on the Company's distribution system typically serve hundreds or thousands of customers along many miles of conductor. The Company's distribution system in its Virginia service territory has approximately 12,000 miles of overhead mainfeeders and 1,900 miles of underground mainfeeders on its approximately 1,900 feeders.

2. Tap Lines

Tap lines are the portion of the distribution system that carry electricity from the mainfeeders to neighborhoods and individual end-use customers. The Company's distribution system in its Virginia service territory includes approximately 19,000 miles of overhead tap lines and approximately 25,000 miles of underground tap lines.

Separate from, but complementary to, the Grid Transformation Plan is the Company's Strategic Undergrounding Program ("SUP"). This program focuses on undergrounding *tap* lines to decrease downed wires and work repair locations, enabling crew redeployment to other outage locations and allowing a faster recovery after severe weather events. In contrast, the focus of grid transformation efforts is largely on the *mainfeeder* portion of the distribution system.

3. Service Lines

Service lines are the low voltage portion of the distribution grid that carries electricity from service transformers to customers. For residential customers, the most common service voltage is 120/240 volt ("V"), meaning appliances and devices using electricity can be connected to either a 120V or a 240V outlet from customers' electrical panels. Commercial and industrial service transformers deliver a variety of service voltages, including 120/208V, 120/240V, and 277/480V. Service lines typically connect to the service transformer on one end and the meter on the other end. In some instances, one service line can be used to serve multiple customers by connecting additional service lines to it along the route from the transformer to the meter.

C. Devices

There are devices installed along the feeders that facilitate the safe and reliable distribution of electricity, including the following:

Voltage control devices. Voltage control devices are used to manage grid voltage to ensure customers receive adequate voltage at the meter. The most common voltage control devices on the distribution grid are voltage regulators and capacitors. Voltage regulators monitor and adjust the voltage at the substation or along the feeder based on control programming that is loaded by Company engineers. The programming typically uses loading and specific electrical information based on the location of the equipment. Capacitors are used to manage power flow efficiency on the distribution grid. As customers use electricity, the equipment along the grid that delivers the power, such as transformers and conductors, consume additional electricity and cause electrical losses to occur, causing voltage to decrease. Capacitors are used to provide a portion of that additional electricity and reduce the losses, which in turn improves voltage.

Stepdown transformers. Stepdown transformers change the voltage level on the distribution wires from a more predominant distribution voltage, such as 35 kV as found at many of the Company's substations, to a less common distribution voltage, such as 6 kV or 4 kV.

Service transformers. Service transformers connect to the grid and serve to lower the voltage from distribution voltages used on the mainfeeders and tap lines, typically 4 kV to 35 kV,

to the service voltage used by customers. The Company has approximately 600,000 service transformers in Virginia.

Protection and control equipment. Protection devices perform several different functions on the distribution grid, including monitoring power flows and voltages, providing switching points to reconfigure power flows, automatically disconnecting a grid segment when a problem is detected, and providing the associated communications functions to allow protection activities to occur. Electronically controlled line devices, fuses, line sensors, relays, and communications gateways are examples of protection and control equipment.

- *Electronically-controlled line reclosers*. Devices that can sense grid problems and take action to de-energize and isolate line sections where necessary, and that can also receive control commands from the advanced distribution management system ("ADMS") using a secure telecommunications network.
- *Line sensors*. Devices installed at select locations along the feeder that provide situational awareness regarding normal loading and voltage, as well as fault related information that can be used by the ADMS to further narrow potential outage locations.
- *Digital relays*. Devices that provide advanced protection and control functionality, and detailed grid performance information including near real-time situational awareness about grid operation.
- *Communication gateways*. Devices that facilitate secure communications and function as a central data hub, sending and receiving all data and control functionality between substations and the ADMS.

D. Meters

Dominion Energy Virginia customers historically have had one of three types of meters: smart (*i.e.*, AMI) meters, automated meter reading ("AMR") meters, or manually read meters.

AMR Meters. The Company began deploying AMR meters throughout the service territory over 20 years ago. Usage data from AMR meters is collected through drive-by readings once a month. Specially equipped trucks used to drive throughout the service territory daily, covering approximately 400 different meter route cycles throughout each month. The Company used meter readers to drive these routes. The equipment collects a meter reading from the AMR meters within range, which the Company then uses for monthly billing. AMR meters cannot be remotely controlled or operated, meaning that the Company must send a field representative for common requests like connecting or disconnecting service. The Company utilized meter servicers to execute these and other requests.

Smart Meters. Smart meters are electric meters that enable two-way communications, digitally gathering energy usage data in specified increments (*i.e.*, interval data) and other related information several times a day. Smart meters are equipped with a network interface card and communicate with each other, creating what is referred to as a mesh network. A system of field telecommunications devices—comprised of devices called repeaters and collectors—gather meter data from the mesh network and transmits the data gathered back to the utility through a backhaul network. Together, the mesh and backhaul networks are called the field area network. A back

office system, also called a head-end system, receives and processes the data and serves as an operating platform for the back office team responsible for operation and maintenance. The term AMI, or "advanced metering infrastructure," refers to the over-arching metering system, which includes smart meters, a field area network, and a back office system.

In 2008, the Company began to deploy AMI in a targeted fashion based on specific operational and customer needs. Taking a measured pace over the course of several years, the Company continued to deploy smart meters in larger quantities and densities in diverse geographical areas of the service territory to validate deployment and operational strategies. The Company used the knowledge gained from this initial deployment of AMI to develop its strategy for full deployment across the service territory. As of December 31, 2024, the Company has fully deployed smart meters across its service territory.

Manually Read Meters. As of December 31, 2024, approximately 19,911 customers have manually read meters, primarily to gather energy usage data in specified increments (*i.e.*, interval data) or monthly peak energy demand. To obtain this data, meter readers visit the customer premises and must walk up to the meter to record energy usage via an electronic "probe" approximately once per month. The meter readers that drive the AMR routes also complete these visits. The Company has deployed manually read meters to support offering time-varying rates to commercial and industrial customers that do not have smart meters. The Company has also deployed manually read meters to provide additional information to net metering customers that do not have smart meters. Finally, the Company has deployed manually read meters for the limited number of customers that have opted out of the Company's smart meter deployment.

E. Operating Systems

1. Customer Experience Systems

Customer Information System ("CIS"). Deployed about 23 years ago, the CIS is the core system delivering business functions such as customer service, account management, credit and collections, service orders, meter inventory, usage, billing, service address management, portfolio management, and rates and financial based activities. The CIS is an employee-facing system, and is also referred to internally as customer business management system ("CBMS").

CBMS is built on a mainframe platform using the programming language COBOL. Users use what is referred to as a "green screen" to view information. The system lacks a logical workflow, requiring users to memorize a series of four letter commands to navigate through screens. The system is not Windows based; nor is it compatible with using a mouse or cursor for simple navigation. The vendor no longer supports the system, and service providers do not routinely hire or train COBOL programmers. The limited services that are available for CBMS come at an increasingly higher cost.

Manage Accounts. Deployed in 2003, Manage Accounts is the customer-facing web self-service platform for residential and small commercial customers.

Key Customer. Deployed in 2006, Key Customer is the customer-facing web self-service system for large customers that are assigned an account representative.

Property Manager Portal. Deployed in 2013, the Property Manager Portal is the customer-facing web self-service tool for property management companies to manage landlord agreements and turn on / turn off service for their properties.

Agency Web Access ("AWA"). Deployed in 2006, Agency Web Access is the customer-facing web self-service application for charities and third-party agencies (*e.g.*, Salvation Army) to make energy assistance payments on behalf of customers.

Meter Data Management System ("MDMS"). Deployed in 2009, the meter data management system is the employee-facing system that processes and stores interval data used for billing and calculates billable consumption for interval meter data.

Gateway. Deployed in 2013, Gateway is the employee-facing web-based front-end system to CBMS and other systems used in the contact center. Gateway is the primary tool for customer service representatives to interact with customers.

Knowledge. Deployed in 2016, Knowledge is the employee-facing system that allows for systematically capturing, describing, organizing, and sharing information including alerts, work processes, and policies across customer service.

E-Gain. Deployed in 2010, E-Gain is the employee-facing system that imports and sorts emails and work tickets, creating a queue for response. E-Gain includes auto replies and templates for responses.

LanBill. Deployed in 1996, LanBill is the employee-facing system that allows back-office personnel to manually edit and print bills flagged for special handling. LanBill is used to process large complex bills that are not fully automated in CBMS.

Bill Image. Deployed in 2003, Bill Image is the employee-facing software used to render an image of the bill on demand in Manage Account and Gateway.

Agiloft. Deployed in 2011, Agiloft is the employee-facing record keeping system used to track elevated customer issues and inquiries.

Demand-side Application ("DSA"): DSA is the employee-facing system used to track inventory and initiate service orders for water heater controls.

State and Local Taxes ("SLT"). SLT is a mainframe application that aggregates taxes at a jurisdictional level for reporting and remittance.

2. Grid Operation Systems

AMI and AMR head-end systems. The system that receives and processes the data and serves as an operating platform for the back-office team responsible for operating and maintaining AMI and AMR, respectively.

Advanced distribution management system ("ADMS"). A software platform that supports a full range of distribution management and optimization tools, such as supervisory control and data acquisition ("SCADA"). The Company implemented the first phase of ADMS in 2019, which provides the basic data acquisition and control functionality. The second phase of ADMS includes building the functionality for fault location, isolation, and service restoration ("FLISR"), a centralized system that leverages an operational model and SCADA to automate fault isolation and reduce the number of customers affected.

Outage management system ("OMS"). A system that provides tools and information to efficiently restore power to customers by providing outage analysis and prediction functionality. The system enhances public and worker safety and serves as the Company's system of record for outage history. The existing OMS was deployed in 1994. The third phase of ADMS includes an OMS replacement that will leverage the real-time operational model from ADMS for improved outage tracking and modernized functionality.

Data analytics system ("DAS"). A system that stores and quickly processes large amounts of data to create advanced analytics solutions. The existing DAS was deployed in 2017.

F. Telecommunications

Dominion Energy Virginia currently has a telecommunications ("telecom") transport portfolio that consists of Company-owned fiber, leased lines, copper cables, microwave, and public carrier solutions. The Company has a network operations center ("NOC") that is responsible for provisioning, testing, monitoring, troubleshooting, and dispatching the Company's telecommunication network year-round.

G. Security

The existing distribution system is protected by a comprehensive security program designed to provide risk-informed, adequate, and cost-effective security control measures that manage the growing threat to the energy sector and protect the Company, its assets, and its customers from cyber and physical attacks. The Company's security program has been subjected to internally conducted and third-party vulnerability assessments and penetration tests (announced and unannounced); peer reviews; and internal and external audits. Results from those engagements inform the Company's continuous improvements to both cyber and physical security.

H. Electric Vehicle Infrastructure

EVs are typically charged by plugging the EV into a charger that is connected to the electric grid. There are three major categories of chargers that are distinguishable by the amount of power the charger can provide, which results in different speeds of charging:

- Level 1 refers to use of a standard 120V outlet, which charges three to five miles of range per hour. Level 1 charging is ideal for overnight charging for EV owners that travel about 30 miles or fewer per day.
- Level 2 chargers require a higher voltage at 240V, which charges 10 to 20 miles of range per hour. Level 2 charging is ideal for workplaces, multi-family dwellings, and locations with the potential for more electric vehicles than chargers.
- Level 3—also known as direct current fast charging ("DC Fast Charge" or "DCFC")—can charge an EV battery to approximately 80% of capacity in 20 to 30 minutes. DCFC requires three-phase electric service and significant capacity. It is ideal for public locations to support travel over long distances.

As of December 31, 2025 there were approximately 1,850 Level 2 (*i.e.*, 240V) and DCFC charging station locations in Virginia available for public use. However, not all of these stations are available to all EV drivers, and some are only available during limited hours.

APPENDIX B: 2026 Integrated Distribution Planning Roadmap

2026 Integrated Distribution Planning Roadmap

Dominion Energy Virginia (or the "Company") defines integrated distribution planning ("IDP")[1] as a consolidated process to address the capacity, performance, reliability, resilience, and distributed energy resource ("DER") integration needs of the distribution grid. In 2019, the Company presented a white paper regarding its preliminary plans to transition to an IDP approach (the "2019 White Paper"). In 2023, the Company presented an updated version of the white paper (the "2023 White Paper"), which provided a progress report on the IDP roadmap, and a timeline for implementation. This white paper (the "2026 White Paper") provides an update on the implementation of the IDP roadmap, including milestones accomplished to date.

Transitioning from traditional distribution planning processes to IDP is an industry-wide effort as the electric power system continues its fundamental shift to the energy transition. This involves moving from centralized large-scale generation and one-way power flows to an evolving paradigm that also includes high penetration levels of variable DERs and bidirectional power flows. The traditional distribution grid was not engineered and built for this evolving purpose. Additional challenges include the increasing frequency and severity of major weather events, such as tropical cyclones and winter storms, and significant forecasted load growth in some regions of the service territory. Therefore, there is a need to review and update the approaches used for designing, planning, and operating modern distribution grids. Consequently, the Company has actively engaged in IDP efforts and will continue to do so as IDP concepts further mature and evolve over the next decade and beyond.

This IDP roadmap provides an overview of the Company's efforts and successes thus far to transition to IDP and establishes tangible goals and timeframes as the Company's distribution planning processes shift toward IDP.

I. Background on Company IDP Efforts

The 2019 White Paper provided an initial conceptual foundation for Dominion Energy's transition toward Integrated Distribution Planning (IDP),[2] emphasizing that this shift requires coordinated changes in people, technologies, and processes. These changes span power system engineering, data analytics, software capabilities, and system integration; each essential for leveraging new technologies and emerging data sources, such as AMI, to optimize planning practices and support a successful IDP.

A core pillar of IDP is the deployment of technologies and secure communications that deliver real-time, wide area visibility across the distribution grid, extending from substations down to

[1] IDP relies on utilizing high-resolution temporal and granular spatial engineering analyses to identify system-wide and locational needs and benefits. The IDP process informs Integrated/Coordinated Resource, Transmission and Distribution (RT&D) planning, Integrated Resource Planning (IRP), or other utility planning processes such as Grid Modernization and capital budgeting. IDP may consider utility, customer, and/or third-party owned DER solutions to accomplish its objectives. IDP also accounts for uncertainties introduced by the dynamic nature of variables impacting grid operation, shifting results and associated decisions from deterministic to probabilistic outcomes. True IDP requires changes in planner's skills, technologies and tools used, and processes. Throughout, trained professionals are vital to fully leverage the technologies and optimize the processes and emerging tool sets. Technologies and communications systems that provide visibility into the distribution grid to the customer premises level are foundational to enabling integrated distribution planning. Processes and tools must then be developed to incorporate the data gathered, including advanced distribution modeling and analysis tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on different parts of the distribution system."

[2] *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2019-00154, Petition, Exhibit 1 (filed Sept. 30, 2019).

individual customers. Once these foundational capabilities are established, new processes and tools must be implemented to transform this data into actionable insights that enhance grid performance, planning, engineering, and operations. This includes advanced distribution modeling and analytical tools capable of evaluating a range of possible future scenarios with varying levels of DER penetration and emerging technologies, and time wide area visibility across the distribution grid, extending from substations down to individual customers. Once these foundational capabilities are established, new processes and tools must be implemented to transform this data into actionable insights that enhance grid performance, planning, engineering, and operations. This includes advanced distribution modeling and analytical tools capable of evaluating a range of possible future scenarios with varying levels of DER penetration and emerging technologies.

Supporting these analyses requires integrating the Company's information systems to efficiently manage the large volumes of data involved. Core analytical functions include distribution system planning and DER/ non-wires alternatives ("NWA") evaluations, complemented by coordinated transmission and distribution ("T&D)" capacity analysis. These are further enhanced by advanced analytical capabilities such as 8760 timeseries simulations, inrush studies, and Value of DER assessments; each essential for developing a comprehensive and data driven distribution planning framework. These functions align with the broader roadmap elements described in the Company's IDP initiative, including forecasting, hosting capacity methodologies, automated modeling tools, and value-based DER analysis planned for implementation of the IDP-series simulations, inrush studies, and Value of DER-driven distribution planning framework-based DER analysis.

Some of these concepts were addressed in the 2023 White Paper and remain true and relevant today (*i.e.*, they are core requirements for the successful implementation of the IDP roadmap).

The Company has made notable progress in the evolution toward IDP since 2023, including:

- Defining the Company's organizational structure so that one team is responsible for all distribution-planning related modeling for load driven investments as well as reliability data analysis activities for reliability driven investments.
- Augmentation of technical staff focused on IDP capability development, including several electric power engineers with advanced degrees and expertise in key areas, such as data analytics and software development.
- Implemented an enhanced Distribution System Model with processes to automate error checks and field validation to aid in the accuracy of the model.
- Implemented LoadSEER for load and DER forecasts; transportation electrification forecasts are currently a separate input into LoadSEER.
- Distributed Generation ("DG") System Impact study analysis continues to be performed by the planning team.
- Time Series analysis is piloted and tested with accurate results and will be implemented in Q4 of 2026.
- Dynamic Distribution system models are created for inrush calculations as required.
- Implementation of processes and software solutions to operationalize the NWA analysis and selection process.

- Publication of three publicly available hosting capacity maps[3,4] which include:
  - Utility-scale generation: it allows identifying the areas of the distribution grid that may be more suitable for interconnection of larger-scale solar generation (e.g., > 1 MW).
  - Residential generation: it allows identifying the areas of the distribution grid that may be more suitable for interconnection of residential (behind-the-meter) solar generation.
  - Electric vehicle: it allows identifying the areas of the distribution system that may be more suitable for transportation electrification.
- A well-established DER interconnection process
- Implementation of non-wires alternatives ("NWA"):
  - Approval of an NWA pilot program under the Company's Grid Transformation Plan (GTP) Phase III filing.
  - Installation of various battery energy storage systems ("BESS"), some including solar generation, to study future NWA (Hanover, New Kent, and Scott projects).
  - Continued construction of the Locks campus microgrid to study future NWA applications and reliability and resilience improvement.
  - Implementation of automated analysis using advanced software to evaluate NWA projects.
- Implementation of AMI:
  - Installation of advanced metering infrastructure ("AMI") across over 99% of its distribution system, enabling the collection of premise-level load and voltage data.
  - Development of an AMI data analytics application to identify and automatically correct meter to service transformer hierarchy relationships that received an Achievement Award from the Association of Edison Illuminated Companies (AEIC).
  - Groundbreaking research on load flow model phase error correction leveraging AMI data, with a technical paper currently pending publication.
- Installation of intelligent grid devices on selected feeders, improving reliability, resilience, and flexibility, and enabling the collection of operational data that improves the accuracy of engineering models.
- Substation technology deployments that not only add enhanced situational awareness and increased system operability and flexibility but provide increasingly granular data that refines the accuracy of the Company's engineering models.
- Ongoing implementation of a DER management system ("DERMS") that monitors and controls selected DER to optimize the operation of the distribution grid.
- Initiated process to integrate different information systems that are vital to enable the analytics initiatives of the IDP roadmap, including modeling and data collection process.
- Participation in numerous research and development projects with industry partners focused on modernizing distribution grid planning, using automated processes and tools and data-driven techniques to improve model data quality and further IDP goals and objectives.

The Company also engaged with Danovo Energy Solutions (formerly Quanta Technology), to solidify the conceptual framework through which the Company views the components of IDP.

II. Updated IDP Roadmap and Implementation Timeline

The 2023 White Paper presented an IDP roadmap that included tangible goals and timeframes

[3] https://www.dominionenergy.com/about/delivering-energy/electric-projects/energy-grid-transformation/hosting-capacity-tool
[4] https://www.dominionenergy.com/about/delivering-energy/electric-projects/ev-capacity-map

to IDP maturity. Figure 1 provides the Company's current roadmap for IDP (the "2026 IDP Roadmap" or the "Roadmap"), which is an updated version of the 2023 filing. The 2026 IDP Roadmap shows the IDP-related capabilities which the Company is committed to focusing on over the next several years, the goal associated with each of those capabilities, a progress report on activities that have been completed, activities that are currently under implementation, and an estimated timeframe for completion, when applicable.

It is worth noting that the IDP concept is not static; important changes have occurred since the preparation of the 2023 White Paper, and further changes are expected in the next decade. Examples include a slowdown in transportation electrification activities due to federal policy changes, and significant forecasted load growth in some regions of the Company's service territory. Additionally, the IDP concept is not uniform across the industry, as there are variations that depend on the specific operating conditions of electric utilities, such as service territory features (weather, environmental conditions, geographic footprint, customer density, *etc.*), distribution grid technology baseline, reliability and resilience performance, DER and electrification penetration levels, regulatory framework, and state policies, *etc.* Therefore, IDP roadmaps must be tailored to address the specific needs of every customer base and service territory and updated to ensure they address the evolving electric utility operating conditions.

The 2026 IDP Roadmap reflects the information available to the Company currently and is based on current system conditions, regulatory requirements, technology maturity, and industry practices. The roadmap prioritizes foundational IDP components, such as advanced load and DER forecasting capabilities, enhanced distribution system modeling, and data integration improvements, recognizing that these elements are prerequisites for more advanced analytical and operational capabilities.

In sequencing initiatives, the Company has carefully balanced resource considerations, including staffing and funding requirements, as well as the technical and procedural interdependencies among roadmap components. Many initiatives are logically sequential, with later-phase capabilities dependent on the successful implementation of foundational tools and processes. Accordingly, the Roadmap is structured to ensure that investments are made in a prudent, phased manner that supports long-term IDP objectives while maintaining operational and financial discipline.

Figure 1: 2026 IDP Roadmap

IDP Component	Goal(s)	Estimated Timeframe
Integrated Capacity Analysis	• Publication and periodic update of static DER hosting capacity analysis maps for public viewing (completed). • Publication and periodic update of static electric transportation hosting capacity analysis for public viewing (completed). • Develop and implement methodology to estimate firm capacity contribution from variable DER. • Develop and implement methodology to *increase/manage* hosting capacity via flexible interconnection.	2021 – 2029

IDP Component	Goal(s)	Estimated Timeframe
	• Develop and implement methodology to calculate dynamic hosting capacity.	
Comprehensive Distribution Grid Load and DER Forecasting	• Acquisition of new load and DER forecasting software (acquisition completed, currently finishing software deployment). • Produce hourly (8760) forecasting on all feeders, including forecasts of load and DER using data from multiple sources, including AMI (currently under implementation, on track to be completed in 2026).	2022 – 2026
Distribution System Model	• Assess options to create secondary (low voltage) system models (completed). • Continue to improve the secondary (low voltage) system model data quality and comprehensiveness of the engineering model (ongoing). • Developed and implemented automated data integrity review/update and model validation process (ongoing). ▪ Objective is identifying and correcting primary (medium voltage) data and model inaccuracies in Geographic Information System (GIS) and Synergi (distribution system analysis software). • Implement a process for creating dynamic/transient models on an as needed basis (ongoing).	2020 – 2029
DER Interconnection	• Implement software solutions that can perform automated time series simulations for interconnection impact studies of utility-scale DERs (ongoing). • Implement an automated process to provide up-to-date and accurate behind-the-meter DER interconnection data to develop GIS and distribution system models (ongoing).	2024 – 2028
Non-wires Alternatives (NWA)	• Identify distribution system needs to be addressed by NWA and review industry practices and experiences (complete). • Develop a methodology to identify and prioritize candidate locations for NWA deployment, including technical and benefit-cost analyses (complete). • Develop a process for deploying utility, customer, and third party-owned/operated NWA (ongoing). • Incorporate NWA selection (behind the meter) and deployment into the distribution planning process (ongoing).	2024 – 2028
Value of DER	• Develop methodology to calculate the location and value of DER for specific value streams of interest (completed). • Implement methodology in software solution to	2024 – 2027

IDP Component	Goal(s)	Estimated Timeframe
	automate periodic calculation of value of DER (ongoing). • Incorporate the value of DER calculation into the overall IDP process in coordination with other initiatives.	
Distribution System Analysis	• Implement software solution that can perform automated time-series (8760 hour) power flow analysis for distribution planning studies (ongoing) • Implement software solutions that can perform automated engineering studies (ongoing).	2021 – 2027
Resilience	• Engage with industry partners, including the Distribution Resilience Working Group[5] of the IEEE Power and Energy Society and contribute to the development of industry standard on metrics for measuring and assessing grid resilience (ongoing). • Develop internal definition, metrics, and methodology for evaluation of distribution system resilience (ongoing). • Identify software and portfolio of solutions for resilience improvement and methodology for cost-effectiveness evaluation and prioritization (ongoing).	2024 – 2027
Advanced Analytics	• Identify and define advanced analytics use cases and applications supporting IDP (ongoing). • Define data and software requirements for advanced analytics applications to IDP (ongoing). • Develop and implement advanced analytics pilot projects (ongoing).	2025 – 2028
Data management and IT integration	• Identify and address data management and IT integration needs to facilitate implementation of IDP roadmap initiatives (ongoing).	2024 – 2028
Coordinated T&D Planning	• Develop co-simulation capability for T&D analysis.	2026 – 2030

Implementation of the IDP roadmap requires the deployment of advanced software and analytics platforms capable of processing large volumes of high-resolution grid and customer data. These tools are necessary to enable distribution system analyses with significantly greater spatial granularity and temporal resolution than traditional planning approaches. This includes performing hourly or sub-hourly evaluations at the service transformer instead of traditional annual or seasonal analyses at the substation or feeder level, where appropriate. This enhanced analytical capability supports more accurate hosting capacity assessments, DER integration studies, load and DER forecasting, reliability and resilience evaluation, and non-wires alternative screening. Achieving this level of analytical rigor requires investments in modern technologies and software tools, strategic partnerships, and specialized expertise. These needs

[5] https://sagroups.ieee.org/distreswg/

are not unique to the Company and are broadly recognized across the industry as foundational to modern distribution planning and grid modernization efforts. Key implementation components include:

- Adoption of advanced grid analytics technologies, including cloud-based computing, scalable data platforms, and artificial intelligence and machine learning tools to enable high-resolution modeling and scenario analysis.
- Ongoing engagement with industry partners, including technology vendors, research institutions, and peer utilities, to pilot, refine, and deploy emerging analytical solutions in a cost-effective and interoperable manner.
- Expanded staffing across multiple disciplines, including engineering, economics, data science, and information technology, to develop, implement, and maintain advanced planning tools and associated analytical processes.

These investments support the Company's objective of enhancing transparency, improving planning accuracy, and enabling data-driven decision-making consistent with regulatory expectations for modern distribution system planning.

Since its prior filing, the Company has reviewed and refined its IDP roadmap and associated implementation timeline to incorporate lessons learned, evolving industry practices, regulatory and policy developments, and stakeholder feedback. These updates reflect the Company's continued commitment to advancing its IDP framework in a deliberate, transparent, and technically sound manner. The updated IDP roadmap provides a structured approach for achieving the Company's long-term IDP objectives, including enhanced system visibility, improved forecasting and hosting capacity analytics, DER integration, and alignment between distribution planning, transmission planning, and resource planning processes. The roadmap is designed to support reliability, resilience, affordability, and compliance with applicable Commission directives.

The Company recognizes that full realization of its IDP vision will extend beyond the current five-year planning horizon. Several roadmap components address emerging technologies, advanced analytical capabilities, data integration enhancements, and evolving market constructs that are still maturing. As such, the implementation timeline reflects a phased approach that prioritizes foundational capabilities in the near term while sequencing more advanced elements in later years. Certain initiatives are positioned in later phases because enabling regulatory frameworks, cost-recovery mechanisms, market signals, or commercially mature solutions are not yet fully established. The Company will continue to monitor regulatory and policy developments and will advance these initiatives as appropriate enabling conditions materialize.

Consistent with Commission expectations, the Company intends to periodically reassess and update the IDP roadmap to reflect evolving system needs, stakeholder input, technological advancements, and regulatory guidance. The Company will provide updates in future IDP reports and remains committed to ongoing collaboration with Commission Staff and stakeholders to ensure that implementation progresses in a prudent and cost-effective manner.

Exhibit 2

EXHIBIT 2

	Description	Citation(s)
Schedule 1	List of approved GT Plan projects and the associated cost caps by phase.	
Schedule 2	General reporting metrics as agreed upon by the Company and Staff	2019 Final Order at 25 (citing Baine Rebuttal Schedule 4) 2021 Final Order at 21 (citing Woomer Direct Schedule 2)
Schedule 3	Mainfeeder hardening – general information and performance metrics by project	2019 Final Order at 25 2023 Final Order at 3 (Report Recommendation 2, Bullet 1, 2, 5), 10
Schedule 4	Mainfeeder hardening – realized benefits compared to projected benefits	2019 Final Order at 25 2023 Final Order at 2-3 (Report Recommendation 2, Bullets 1, 2, 3, 4), 10
Schedule 5	Mainfeeder hardening – performance of hardened mainfeeder sections during severe weather events	2023 Final Order at 2-3 (Report Recommendation 2, Bullet 7), 10
Schedule 6	Mainfeeder hardening – actual costs compared to estimates	2023 Final Order at 3 (Report Recommendation 2, Bullet 6), 10
Schedule 7	Information on mainfeeders targeted by both mainfeeder hardening and the targeted corridor improvement tree overhang removal pilot	2023 Final Order at 3 (Report Recommendation 2, Bullet 8), 10
Schedule 8	Targeted corridor improvement hazard tree pilot – areas identified by AI	2023 Final Order at 11
Schedule 9	Voltage island mitigation – measurable benefits	2021 Final Order at 15, 22
Schedule 10	Information on how the grid technologies projects will support integrated planning	2021 Final Order at 21-22
Schedule 11	Intelligent grid devices and FLISR – costs (projected and actual) and performance metrics by project	2021 Final Order at 19, 22
Schedule 12	DERMS – various uses, including visibility of DERs and ability to leverage smart inverter functionality	2021 Final Order at 20, 22
Schedule 13	Voltage optimization enablement – projects by type and average cost per upgrade project (planned and actual)	2021 Final Order at 21 n.99 (citing Volkmann Direct at 18-19)
Schedule 14	Non-wires alternative pilot – progress developing metrics list	2023 Final Order at 12

Relevant Orders

Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service, Case No. PUR-2019-00154, Final Order (Mar. 26, 2020).

Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, Case No. PUR-2021-00127, Final Order (Jan. 7, 2022).

Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, Case No. PUR-2023-00051, Final Order (Sept. 18, 2023).

Schedule 1

Total GT Plan Capital	Phase I Cost Cap	Phase II Cost Cap	Phase III Cost Cap	Phase IIIB Cost Cap
Advanced Metering Infrastructure (AMI)		$186,087,775	$23,234,517	
Customer Information Platform / Meter Data Management (CIP/MDM)	$83,682,659	$134,965,805	$4,315,245	
Mainfeeder Hardening	$47,891,469		$182,719,475	$234,739,791
Targeted Corridor Improvement				
Voltage Island Mitigation[1]	$6,694,356	$13,865,962	$25,325,122	
Intelligent Grid Devices		$29,099,153		
Fault Location, Isolation, Service Restoration Software (FLISR)		$10,013,077		
Outage Management System (OMS)			$15,662,607	$19,100,000
Distributed Energy Resources Management System (DERMS)[1]		$6,166,253	$8,201,064	
Hosting Capacity[2]	$314,529			
Enterprise Asset Management System (EAMS)		$18,767,131		
Voltage Optimization Enablement		$97,146,210	$215,000,000	
Substation Technology Deployment[1]		$34,489,646	$144,099,313	
Non-Wires Alternative (NWA) Pilot[3]			$50,000,000	
Locks Campus Microgrid[2]	$13,069,784			
Physical Security[2]	$9,342,877	$37,309,573	$71,005,873	
Telecommunications	$53,026,891	$97,867,202	$83,040,414	
Cyber Security	$1,145,585	$6,481,508	$468,652	
Stakeholder Engagement & Customer Education				
Smart Charging Infrastructure Pilot	$3,849,700			
Image Management and Analytics Program (IMAP)				$24,431,800
Total GT Plan Capital	**$219,017,850**	**$672,259,295**	**$823,072,282**	**$278,271,591**

Total GT Plan O&M	Phase I Cost Cap	Phase II Cost Cap	Phase III Cost Cap	Phase IIIB Cost Cap
Advanced Metering Infrastructure (AMI)		$12,199,836	$23,200,003	
Customer Information Platform / Meter Data Management (CIP/MDM)	$27,043,791	$68,876,269		
Mainfeeder Hardening				
Targeted Corridor Improvement[2]	$12,819,371	$16,271,982	$31,937,372	
Voltage Island Mitigation				
Intelligent Grid Devices		$21,900		
Fault Location, Isolation, Service Restoration Software (FLISR)		$874,796		
Outage Management System (OMS)			$1,000,000	$1,548,472
Distributed Energy Resources Management System (DERMS)			$1,102,986	
Hosting Capacity	$52,288			
Enterprise Asset Management System (EAMS)		$1,248,611		
Voltage Optimization Enablement				
Substation Technology Deployment				
Non-Wires Alternative (NWA) Pilot[3]			$332,431	
Locks Campus Microgrid	$79,478			
Physical Security[4]		$240,138		
Telecommunications	$1,616,791	$4,089,921	$12,143,885	
Cyber Security	$360,494	$2,790,376		
Stakeholder Engagement & Customer Education	$2,700,610	$3,033,271	$1,095,000	
Smart Charging Infrastructure Pilot	$16,216,230			
Image Management and Analytics Program (IMAP)				$3,050,040
Total GT Plan O&M	**$60,889,052**	**$109,647,100**	**$70,811,677**	**$4,598,512**

[1] *Represents revised Phase II cost caps approved in Case No. PUR-2023-00136*

[2] *Represents revised Phase I cost caps approved in Case No. PUR-2022-00140*

[3] *Phase III cost cap reflects years 2024 through 2026 as approved in Case No. PUR-2023-00051*

[4] *Represents revised Phase I cost caps approved in Case No. PUR-2022-00140*

Schedule 2

Category	Metrics	Witness / Owner	2015 - 2019 Avg.	2020	2021	2022	2023	2024	2025
Reduced outage events[1]	SAIDI	Alfayyoumi	134.9	141.0	133.5	136.0	123.3	131.3	144.4
	SAIFI	Alfayyoumi	1.22	1.26	1.16	1.20	1.16	1.21	1.32
	# of outages avoided	Alfayyoumi		1,011	2,734	(1,034)	2,598	2,601	(6,466)
	# of minutes avoided	Alfayyoumi		(6.0)	1.5	(1.1)	11.6	(3.6)	(10.1)
	# of unplanned outage events	Alfayyoumi	42,043	41,378	38,905	42,077	37,430	38,374	45,277
Faster restoration time[1]	# Customer minutes of interruption	Alfayyoumi	332,004,262	357,594,037	343,683,784	352,265,206	322,130,158	345,929,486	404,696,929
Improved grid visibility & support DER integration	# of IGDs deployed	Walker				83	109	121	137
	% of distribution system with enhanced telemetry	Walker				1%	2%	2%	2%
	# of DERs located on circuits with IGD	Stevens				4	4	4	6
	# of DERs integrated into DERMS	Stevens							43,365
	MW of DERs integrated into DERMS	Stevens							98
	# of front-of-the-meter DERs integrated into DERMS	Stevens							4
	MW of front-of-the-meter DERs integrated into DERMS	Stevens							45
	# of behind-the-meter DERs integrated into DERMS	Stevens							43,361
	MW of behind-the-meter DERs integrated into DERMS	Stevens							53
	# of customer programs integrated into DERMS	Stevens							2
	# of distinct vendor assets integrated into DERMS	Stevens							2
Telecommunications	# of key facilities the Company has deployed Tier 2 telecommunications solutions	Carroll		57	64	21	24	38	40
	Miles of fiber deployed [2]	Walker		-	38.7	110.8	152.2	134.9	118.5
Improved support for Distributed Energy Resource ("DER") integration	# of Net Metering interconnection requests completed	Stevens	1,236	4,818	7,482	11,208	9,710	9,153	7,161
	# of Small Generator Interconnection Agreements completed	Stevens	15	15	28	49	44	49	65
Smart Charging Infrastructure Pilot	Public Fast Charging Rebates	Staples		0	13	6	10		
	Public Fast Charging Funds Deployed	Staples		$0	$550,635	$199,468	$445,280		
	Multi-Family Charging Rebates	Staples		0	14	6	1		
	Multi-Family Charging Funds Deployed	Staples		$0	$133,799	$69,530	$14,786		
	Workplace Charging Rebates	Staples		0	31	40	133		
	Workplace Charging Funds Deployed	Staples		$0	$281,856	$320,609	$915,508		
	Transit Charging Rebates	Staples		0	0	0	0		
	Transit Charging Funds Deployed	Staples		$0	$0	$0	$0		
Customer Education [3]	# of direct communications	McQuain		1,272,283	24,536	1,789,117	268,409	225,138	227,924
	# of digital impressions	McQuain		171,168	1,040,225	200,028	191,110	82,705	346,197
	# of public meetings and events	McQuain		28	42	34	2	6	0
Reduced service order completion times	# of remote service orders executed	Holland	178,886	195,838	318,621	750,896	898,355	1,497,425	1,542,006
	% of total service orders executed remotely	Holland	19.7%	29.1%	47.6%	75.1%	79.3%	92.9%	92.5%
	# of same-day service orders completed	Holland		12,581	20,728	152,307	54,828 [4]	15,680	16,251
Better management of energy diversion	Annual energy diversion recovery ($)	Holland	1,921	2,513	3,658	44,471	5,558	559	0
	Annual energy diversion expenses ($)	Holland	1,218,614	945,206	959,058	1,166,296	765,041	1,511,650	4,264,199
	# of AMI identified energy diversion customers / incidents	Holland	11	14	26	409	295	625	1,319
Improved billing & meter read rate accuracy	# of escalated bill-related customer complaints		537	273	312	825	1,536	1,225	711
	# of monthly bills estimated			156,180	200,383	219,307	23,151 [4]	195,563	63,439
AMI detection of issues	# of voltage violations managed based upon AMI detection	Walker	7	4	4	118 [8]	2,738	7,179	10,600
	# of outages detected remotely by AMI	Holland	509,415	670,657	1,011,487	2,212,568	1,788,970	2,447,913	2,969,825
Field labor savings	# of truck rolls reduced (Mainfeeder Hardening) [5]	Alfayyoumi		9	15	26	27	1	11
	# of truck rolls reduced (Targeted Corridor Improvement) [6]	Alfayyoumi		-	269	(214)	29	(249)	(295)
	Restoration OT Hrs [1]		175,784	195,224	182,631	189,600	191,302	202,174	228,749
	Average OT per lineworker		425	405	363	389	182	231	463
	# reduced found-ons	Holland		3,413	6,410	15,029	14,300	16,384	16,549
Reduced storm damage restoration costs	Tree trimming expenses	Alfayyoumi	14,759,255	14,304,924	21,460,892	23,753,917	16,805,785	12,933,276	23,669,067
	# of storm truck rolls reduced (Mainfeeder Hardening) [5]	Alfayyoumi		(2)	2	(7)	26	35	35
	# of storm truck rolls reduced (Targeted Corridor Improvement) [6]	Alfayyoumi		-	111	(390)	435	459	459

[1] *Excluding major events*

[2] *Mileage reflects only projects that are accounting closed*

[3] *Totals exclude AMI-specific communications*

[4] *Reflects totals for Jan. to Mar. 2023*

[5] *For completed circuit(s) only: 3-phase device events only, excluding major events*

[6] *For ash tree mitigation completed circuit(s) only, excluding major events*

Schedule 2

Category	Metrics	Witness	Status
Modernized customer relationship by delivering better information and value to each customer	Outage Center app	Jennings	Deployed November 2019
	Notification Preferences	Jennings	Initial Deployment April 2020
	What-if Analysis / Rate Comparison by 2023	Jennings	Implemented April 2023
	e-Bill upgrade to include graphical usage information by 2023	Jennings	Residential Schedule 1 bill calculator available on DominionEnergy.com
	Notification & Alert Options through preferred channel by 2023	Jennings	Deployed April 2023
	Account specific details on charges available to customers within online portal by 2023	Jennings	Deployed 2023
	Bill re-design by 2024	Jennings	Implemented November 2024
	Average monthly number of bill complaints	Jennings	28
	Average monthly number of bills requiring manual intervention	Jennings	13
Expanded set of self-service options and digital communication channels	Dominion Energy Mobile Application	Jennings	Deployed September 2020, updated April 2023
	List of digital communication channels introduced	Jennings	Introduced one with mobile app
	# of customers enrolled in each channel	Jennings	Emails: 1,852,980 Phone: 326,285
	# of times online information is accessed annually for each communication channel.	Jennings	Web: 1,303,067 App: 607,010
New rate structures	# of customers enrolled in opt-in time-varying rate program		14,740
Reduced likelihood of successful cyber & physical attacks	# of cyber or physical security events associated with GT Plan that require further investigation or analysis. (This information to be reported separately and confidentially)	Bransky	This information is confidential. The Company has committed to communicate applicable information, in person, at Staff's request.

Mainfeeder Hardening

Requirement: General information and performance metrics. 2023 Final Order at 3

Circuit	Mainfeeders hardened	Miles hardened	Date Complete	Cost per mile [1]
04331	1	1.9	10/1/2020	$658,683
01450	1	1.0	3/30/2021	$591,829
25487	1	5.0	11/1/2021	$719,565
04308	1	4.0	11/25/2021	$901,331
04334	1	3.9	12/1/2021	$428,397
04395	1	3.6	12/2/2021	$590,365
06460	1	4.0	12/2/2021	$576,881
01300	1	14.7	1/14/2022	$664,944
65911	1	14.0	3/8/2022	$473,497
23325	1	5.0	4/18/2022	$1,011,275
26340	1	3.1	4/18/2022	$1,653,547
25452	1	2.1	8/31/2022	$1,852,742
03315	1	6.7	9/27/2022	$310,428
65937	1	6.3	10/20/2022	$417,851
84385	1	9.4	11/2/2022	$525,882
47327	1	6.5	11/23/2022	$315,079
05329	1	4.2	1/17/2023	$820,566
06461	1	6.8	2/20/2023	$228,562
01385	1	3.3	2/23/2023	$513,989
63309	1	7.3	3/1/2023	$392,512
04304	1	5.8	3/21/2023	$999,467
65326	1	5.6	3/29/2022	$1,256,307
81383	1	4.8	4/5/2023	$466,973
81375	1	9.2	5/2/2023	$742,782
03350	1	6.0	5/30/2023	$419,934
86832	1	2.8	6/15/2023	$1,564,648
48442	1	7.3	6/20/2023	$1,342,351
04333	1	13.1	6/29/2023	$778,894
81350	1	5.2	7/24/2023	$788,559
05358	1	1.3	7/24/2023	$834,751
46320	1	1.7	7/26/2023	$564,181
42495	1	4.5	8/2/2023	$411,639
66404	1	6.5	8/7/2023	$214,308
82355	1	7.4	8/28/2023	$601,769
65497	1	7.2	9/19/2023	$364,574
05332	1	5.2	10/3/2023	$737,505
81390	1	6.7	11/3/2023	$554,185
81376	1	9.6	11/30/2023	$405,612
02342	1	9.8	12/4/2023	$453,177
85871	1	5.0	12/7/2023	$629,440
46474	1	2.5	12/22/2023	$642,600
81365	1	1.8	1/16/2024	$1,280,076
46877	1	2.9	3/5/2024	$1,050,730
05345	1	3.9	3/15/2024	$1,429,617
05568	1	2.4	4/1/2024	$1,170,083
81519	1	11.8	4/9/2024	$766,445
48726	1	6.9	5/21/2024	$780,256
85883	1	7.4	5/21/2024	$683,409
44721	1	8.3	6/27/2024	$1,015,087
03367	1	6.8	8/28/2024	$557,777
81367	1	4.7	11/7/2024	$790,677
04303	1	5.4	11/13/2024	$240,446
06426	1	4.8	11/21/2024	$632,703
41358	2	3.7	12/17/2024	$1,178,266
46522	1	8.9	12/20/2024	$1,273,993
02318	1	6.2	4/30/2025	$859,962
66401	1	4.2	6/10/2025	$614,482
63320	1	21.2	12/10/2025	$1,322,312

[1] Life to date costs thru December 31, 2025

All Construction Completed Feeders			
Year	Miles Hardened	Critical Services	Customers Targeted
2020	1.9	4	801
2021	21.5	36	17,542
2022	67.8	22	17,728
2023	148.8	56	63,452
2024	79.7	19	33,443
2025	31.6	7	5,477
Total	351.3	144	138,443

	Total Outage Events 3 Phase Device events Ex ME							Max Outage Event Duration (Min) - Device events Ex ME							SAIDI ExME						
Circuit[2]	Baseline	2021	2022	2023	2024	2025	Yearly Average	Baseline	2021	2022	2023	2024	2025	Yearly Average	Qualifying Baseline	2021	2022	2023	2024	2025	Yearly Average
04331	13	7	14	1	3	1	5	906	766	1,092	903	424	328	703	359	289	764	76	185	66	276
01450	9	an 12 months	4	4	7	6	5	2,520	an 12 months	5,379	666	1,060	790	1,974	333	an 12 months	587	231	319	127	316
15481	13	an 12 months	6	5	3	4	5	1,197	an 12 months	982	838	1,636	936	1,137	382	an 12 months	332	336	139	154	216
04308	13	an 12 months	8	10	19	15	13	1,536	an 12 months	1,206	936	843	769	939	313	an 12 months	244	309	272	170	249
04334	9	an 12 months	9	8	13	14	11	1,010	an 12 months	1,139	998	634	889	915	235	an 12 months	202	69	139	159	142
04395	8	an 12 months	1	2	3	6	3	1,597	an 12 months	657	313	308	632	478	333	an 12 months	121	73	73	458	181
06460	13	an 12 months	7	10	20	21	15	2,452	an 12 months	1,076	822	923	1,099	980	418	an 12 months	184	157	438	657	359
01300	11	an 12 months	an 12 months	11	12	13	12	2,342	an 12 months	han 12 months o	1,127	1,048	895	1,023	838	an 12 months	an 12 months	306	368	793	489
65911	5	an 12 months	an 12 months	15	8	10	11	1,901	an 12 months	han 12 months o	1,377	1,284	1,720	1,460	305	an 12 months	an 12 months	360	249	224	277
23325	19	an 12 months	an 12 months	12	18	13	14	1,235	an 12 months	han 12 months o	935	1,048	1,530	1,171	315	an 12 months	an 12 months	425	136	170	244
26340	13	an 12 months	an 12 months	8	5	12	8	441	an 12 months	han 12 months o	428	225	1,005	553	135	an 12 months	an 12 months	25	113	290	143
25452	14	an 12 months	an 12 months	8	7	9	8	1,370	an 12 months	han 12 months o	780	513	948	747	308	an 12 months	an 12 months	151	246	133	177
03315	19	an 12 months	an 12 months	16	8	22	15	1,303	an 12 months	han 12 months o	942	730	950	874	308	an 12 months	an 12 months	226	204	464	298
65937	12	an 12 months	an 12 months	7	2	5	5	1,661	an 12 months	han 12 months o	1,321	552	695	856	428	an 12 months	an 12 months	356	99	176	210
84385	16	an 12 months	an 12 months	13	13	18	15	838	an 12 months	han 12 months o	1,009	1,386	721	1,039	454	an 12 months	an 12 months	441	120	1,053	538
47377	5	an 12 months	an 12 months	10	6	8	8	1,826	an 12 months	han 12 months o	1,535	847	494	959	646	an 12 months	an 12 months	352	405	412	389
05329	6	an 12 months	an 12 months	an 12 months	11	6	9	2,202	an 12 months	han 12 months o	han 12 months o	778	1,413	1,096	170	an 12 months	an 12 months	an 12 months	456	170	313
06461	21	an 12 months	an 12 months	an 12 months	24	9	17	2,472	an 12 months	han 12 months o	han 12 months o	1,286	705	996	276	an 12 months	an 12 months	an 12 months	284	72	178
01385	19	an 12 months	an 12 months	an 12 months	23	21	22	995	an 12 months	han 12 months o	han 12 months o	1,236	1,210	1,223	233	an 12 months	an 12 months	an 12 months	145	605	375
63309	19	an 12 months	an 12 months	an 12 months	15	10	13	2,132	an 12 months	han 12 months o	han 12 months o	950	933	942	257	an 12 months	an 12 months	an 12 months	420	193	307
04304	6	an 12 months	an 12 months	an 12 months	4	11	8	1,053	an 12 months	han 12 months o	han 12 months o	625	650	638	283	an 12 months	an 12 months	an 12 months	138	196	167
65326	4	an 12 months	an 12 months	an 12 months	4	7	6	723	an 12 months	han 12 months o	han 12 months o	609	1,094	852	537	an 12 months	an 12 months	an 12 months	170	590	380
81383	5	an 12 months	an 12 months	an 12 months	2	3	3	1,824	an 12 months	han 12 months o	han 12 months o	787	914	851	314	an 12 months	an 12 months	an 12 months	121	343	232
81375	10	an 12 months	an 12 months	an 12 months	9	4	7	10,097	an 12 months	han 12 months o	han 12 months o	788	1,250	1,019	512	an 12 months	an 12 months	an 12 months	86	104	95
03350	16	an 12 months	an 12 months	an 12 months	17	15	16	1,679	an 12 months	han 12 months o	han 12 months o	1,270	967	1,119	188	an 12 months	an 12 months	an 12 months	232	172	202
86432	10	an 12 months	an 12 months	an 12 months	8	17	13	2,015	an 12 months	han 12 months o	han 12 months o	1,585	1,451	1,518	1,037	an 12 months	an 12 months	an 12 months	703	792	748
48442	18	an 12 months	an 12 months	an 12 months	12	16	14	1,401	an 12 months	han 12 months o	han 12 months o	1,705	1,525	1,615	389	an 12 months	an 12 months	an 12 months	377	246	311
04333	7	an 12 months	an 12 months	an 12 months	8	14	11	926	an 12 months	han 12 months o	han 12 months o	710	787	749	298	an 12 months	an 12 months	an 12 months	152	417	284
81350	13	an 12 months	an 12 months	an 12 months	7	5	6	1,241	an 12 months	han 12 months o	han 12 months o	526	1,099	813	380	an 12 months	an 12 months	an 12 months	214	99	156
05358	10	an 12 months	an 12 months	an 12 months	6	12	9	1,507	an 12 months	han 12 months o	han 12 months o	943	1,237	1,090	233	an 12 months	an 12 months	an 12 months	199	131	165
46320	7	an 12 months	an 12 months	an 12 months	1	4	3	858	an 12 months	han 12 months o	han 12 months o	582	859	721	141	an 12 months	an 12 months	an 12 months	14	33	24
42495	11	an 12 months	an 12 months	an 12 months	9	9	9	1,090	an 12 months	han 12 months o	han 12 months o	901	520	711	255	an 12 months	an 12 months	an 12 months	100	82	91
66404	14	an 12 months	an 12 months	an 12 months	10	13	12	876	an 12 months	han 12 months o	han 12 months o	782	1,007	895	492	an 12 months	an 12 months	an 12 months	229	320	274
82355	13	an 12 months	an 12 months	an 12 months	19	18	19	1,587	an 12 months	han 12 months o	han 12 months o	1,147	1,106	1,127	310	an 12 months	an 12 months	an 12 months	72	120	96
65497	5	an 12 months	an 12 months	an 12 months	7	9	8	1,650	an 12 months	han 12 months o	han 12 months o	823	1,359	1,091	152	an 12 months	an 12 months	an 12 months	177	339	258
05332	3	an 12 months	an 12 months	an 12 months	9	7	8	884	an 12 months	han 12 months o	han 12 months o	789	581	685	176	an 12 months	an 12 months	an 12 months	165	180	173
81390	11	an 12 months	an 12 months	an 12 months	10	13	12	1,613	an 12 months	han 12 months o	han 12 months o	938	1,119	1,029	260	an 12 months	an 12 months	an 12 months	422	288	355
81376	10	an 12 months	an 12 months	an 12 months	7	9	8	1,250	an 12 months	han 12 months o	han 12 months o	649	700	675	359	an 12 months	an 12 months	an 12 months	231	264	247
02347	12	an 12 months	an 12 months	an 12 months	7	4	6	1,073	an 12 months	han 12 months o	han 12 months o	1,144	654	899	334	an 12 months	an 12 months	an 12 months	321	135	228
85871	4	an 12 months	an 12 months	an 12 months	9	8	9	916	an 12 months	han 12 months o	han 12 months o	914	612	763	344	an 12 months	an 12 months	an 12 months	307	217	262
46474	5	an 12 months	an 12 months	an 12 months	2	9	6	1576	an 12 months	han 12 months o	han 12 months o	335	526	431	311	an 12 months	an 12 months	an 12 months	7	103	55
81365	14	an 12 months	an 12 months	an 12 months	an 12 months	3	3	1183	an 12 months	han 12 months o	han 12 months o	than 12 months of	358	358	336	an 12 months	an 12 months	an 12 months	an 12 months	76	76
46977	5	an 12 months	an 12 months	an 12 months	an 12 months	1	1	782	an 12 months	han 12 months o	han 12 months o	than 12 months of	874	874	361	an 12 months	an 12 months	an 12 months	an 12 months	192	192
05345	6	an 12 months	an 12 months	an 12 months	an 12 months	11	11	972	an 12 months	han 12 months o	han 12 months o	than 12 months of	607	607	148	an 12 months	an 12 months	an 12 months	an 12 months	134	134
05568	4	an 12 months	an 12 months	an 12 months	an 12 months	1	1	1295	an 12 months	han 12 months o	han 12 months o	than 12 months of	703	703	351	an 12 months	an 12 months	an 12 months	an 12 months	52	52
81519	7	an 12 months	an 12 months	an 12 months	an 12 months	0	0	1522	an 12 months	han 12 months o	han 12 months o	than 12 months of	676	676	458	an 12 months	an 12 months	an 12 months	an 12 months	208	208
48726	10	an 12 months	an 12 months	an 12 months	an 12 months	16	16	1924	an 12 months	han 12 months o	han 12 months o	than 12 months of	759	759	227	an 12 months	an 12 months	an 12 months	an 12 months	216	216
85883	6	an 12 months	an 12 months	an 12 months	an 12 months	7	7	1727	an 12 months	han 12 months o	han 12 months o	than 12 months of	881	881	273	an 12 months	an 12 months	an 12 months	an 12 months	165	165
44721	23	an 12 months	an 12 months	an 12 months	an 12 months	18	18	1578	an 12 months	han 12 months o	han 12 months o	than 12 months of	967	967	521	an 12 months	an 12 months	an 12 months	an 12 months	358	358
03367	10	an 12 months	an 12 months	an 12 months	an 12 months	12	12	1323	an 12 months	han 12 months o	han 12 months o	than 12 months of	1091	1,091	342	an 12 months	an 12 months	an 12 months	an 12 months	304	304
81367	9	an 12 months	an 12 months	an 12 months	an 12 months	7	7	1328	an 12 months	han 12 months o	han 12 months o	than 12 months of	341	341	246	an 12 months	an 12 months	an 12 months	an 12 months	86	86
06426	7	an 12 months	an 12 months	an 12 months	an 12 months	8	8	1515	an 12 months	han 12 months o	han 12 months o	than 12 months of	905	905	178	an 12 months	an 12 months	an 12 months	an 12 months	302	302
41358	9	an 12 months	an 12 months	an 12 months	an 12 months	6	6	1003	an 12 months	han 12 months o	han 12 months o	than 12 months of	735	735	235	an 12 months	an 12 months	an 12 months	an 12 months	322	322
44622	11	an 12 months	an 12 months	an 12 months	an 12 months	8	8	1595	an 12 months	han 12 months o	han 12 months o	than 12 months of	954	964	395	an 12 months	an 12 months	an 12 months	an 12 months	255	255
Total Average	11	7	7	9	9	10	9	1581	766	1648	933	885	897	908	339	289	334	243	226	266	244

[2] *Data syncronized by colonder year as directed by the Commission ([PUR-2023-00051])*

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Schedule 3

SAIFI ExME							CAIDI ExME							Montly Average CMI 3 Phase ExME	
Baseline	2021	2022	2023	2024	2025	Yearly Average	Baseline	2021	2022	2023	2024	2025	Yearly Average	Baseline	CMI After Project Completion
3.3	2.2	5.6	0.3	1.6	0.4	2.0	110	131	137	220	116	169	155	57,511	11,439
3.4	than 12 months of	2.3	1.2	2.5	2.6	2.2	98	n/a	256	193	126	49	156	32,007	15,858
1.8	than 12 months of	1.4	1.8	1.5	0.6	1.5	160	n/a	190	184	111	153	161	29,838	11,645
2.8	than 12 months of	1.1	3.4	3.4	1.8	2.4	113	n/a	229	92	79	95	124	43,498	41,194
2.5	than 12 months of	2.4	1.5	1.9	1.3	1.8	96	n/a	85	47	74	126	83	43,229	26,858
2.4	than 12 months of	0.6	0.3	0.4	2.8	1.0	136	n/a	205	244	177	165	198	29,486	1,901
3.4	than 12 months of	1.0	1.3	5.0	2.5	2.5	123	n/a	182	118	87	260	162	49,014	30,582
5.1	than 12 months of	12 months	3.4	5.1	7.4	5.3	163	n/a	n/a	89	72	107	89	40,819	26,359
2.1	than 12 months of	12 months	1.9	2.5	1.2	1.9	143	n/a	n/a	189	101	188	159	12,906	19,832
2.4	than 12 months of	12 months	4.0	3.3	2.5	3.3	133	n/a	n/a	105	41	68	71	33,265	31,117
1.2	than 12 months of	12 months	0.3	1.2	2.8	1.5	116	n/a	n/a	89	92	102	94	27,371	25,830
2.3	than 12 months of	12 months	2.3	1.9	1.2	1.8	133	n/a	n/a	64	127	107	100	38,141	23,410
2.9	than 12 months of	12 months	2.6	1.7	4.2	2.9	107	n/a	n/a	86	118	110	105	35,936	47,223
2.4	than 12 months of	12 months	2.2	0.7	1.3	1.4	178	n/a	n/a	165	136	132	144	43,382	8,534
3.8	than 12 months of	12 months	4.2	1.6	4.6	3.4	120	n/a	n/a	106	74	231	137	48,665	91,323
2.9	than 12 months of	12 months	2.3	2.4	5.2	3.3	223	n/a	n/a	153	171	80	134	20,594	15,162
1.4	than 12 months of	12 months	12 months	3.1	0.7	1.9	125	n/a	n/a	n/a	146	249	198	22,306	30,251
2.6	than 12 months of	12 months	12 months	4.3	1.4	2.8	107	n/a	n/a	n/a	66	53	59	48,060	38,395
2.2	than 12 months of	12 months	12 months	1.1	3.0	2.1	108	n/a	n/a	n/a	132	199	165	34,096	77,832
2.7	than 12 months of	12 months	12 months	3.4	2.0	2.7	96	n/a	n/a	n/a	125	96	111	23,308	19,306
3.0	than 12 months of	12 months	12 months	1.8	1.9	1.8	98	n/a	n/a	n/a	78	104	91	50,012	16,187
2.7	than 12 months of	12 months	12 months	1.4	1.0	1.2	199	n/a	n/a	n/a	119	615	367	31,074	20,596
2.0	than 12 months of	12 months	12 months	0.6	2.3	1.4	158	n/a	n/a	n/a	220	147	183	22,557	259
3.3	than 12 months of	12 months	12 months	1.3	1.0	1.1	153	n/a	n/a	n/a	65	107	86	33,438	7,677
1.6	than 12 months of	12 months	12 months	2.5	1.1	1.8	118	n/a	n/a	n/a	94	160	127	21,706	24,180
3.5	than 12 months of	12 months	12 months	2.4	4.0	3.2	300	n/a	n/a	n/a	299	198	249	56,814	40,858
2.9	than 12 months of	12 months	12 months	2.3	2.2	2.3	135	n/a	n/a	n/a	161	110	136	70,915	58,153
2.6	than 12 months of	12 months	12 months	1.4	2.9	2.2	115	n/a	n/a	n/a	106	142	124	30,677	23,018
2.2	than 12 months of	12 months	12 months	2.1	1.2	1.6	173	n/a	n/a	n/a	102	84	93	49,745	19,394
1.3	than 12 months of	12 months	12 months	1.2	1.3	1.3	175	n/a	n/a	n/a	164	98	131	38,485	7,653
1.6	than 12 months of	12 months	12 months	0.1	0.2	0.2	88	n/a	n/a	n/a	147	147	147	14,464	158
1.7	than 12 months of	12 months	12 months	1.3	0.5	0.9	154	n/a	n/a	n/a	78	165	121	62,642	22,317
2.9	than 12 months of	12 months	12 months	1.4	1.6	1.5	170	n/a	n/a	n/a	166	205	186	46,233	12,205
2.8	than 12 months of	12 months	12 months	1.3	1.1	1.2	111	n/a	n/a	n/a	56	114	85	59,067	21,100
0.9	than 12 months of	12 months	12 months	1.0	1.7	1.3	173	n/a	n/a	n/a	185	197	191	12,593	23,668
1.8	than 12 months of	12 months	12 months	1.8	2.0	1.9	96	n/a	n/a	n/a	94	88	91	14,659	20,985
2.7	than 12 months of	12 months	12 months	2.5	1.9	2.2	97	n/a	n/a	n/a	172	154	163	11,658	10,269
2.6	than 12 months of	12 months	12 months	2.2	2.2	2.2	140	n/a	n/a	n/a	105	120	112	21,931	15,173
2.3	than 12 months of	12 months	12 months	1.6	0.6	1.1	145	n/a	n/a	n/a	200	223	212	46,744	26,712
1.5	than 12 months of	12 months	12 months	1.2	2.4	1.8	223	n/a	n/a	n/a	248	92	170	26,901	14,961
3	than 12 months of	12 months	12 months	0	3.1	1.6	112	n/a	n/a	n/a	130	33	82	17832	4818
3	than 12 months of	12 months	12 months	n 12 months	0.5	0.5	99	n/a	n/a	n/a	n/a	145	145	67851	918
3	than 12 months of	12 months	12 months	n 12 months	1.3	1.3	130	n/a	n/a	n/a	n/a	146	146	26612	2413
1	than 12 months of	12 months	12 months	n 12 months	2.0	2.0	119	n/a	n/a	n/a	n/a	66	66	23083	29103
2	than 12 months of	12 months	12 months	n 12 months	0.8	0.8	204	n/a	n/a	n/a	n/a	63	63	4146	111
2	than 12 months of	12 months	12 months	n 12 months	0.8	0.8	207	n/a	n/a	n/a	n/a	260	260	34532	0
2	than 12 months of	12 months	12 months	n 12 months	1.7	1.7	115	n/a	n/a	n/a	n/a	126	126	20203	44735
1	than 12 months of	12 months	12 months	n 12 months	2.8	2.8	191	n/a	n/a	n/a	n/a	58	58	21994	9459
4	than 12 months of	12 months	12 months	n 12 months	3.4	3.4	131	n/a	n/a	n/a	n/a	105	105	88589	37537
2	than 12 months of	12 months	12 months	n 12 months	2.6	2.6	138	n/a	n/a	n/a	n/a	118	118	36311	31265
3	than 12 months of	12 months	12 months	n 12 months	1.5	1.5	98	n/a	n/a	n/a	n/a	57	57	51077	14964
2	than 12 months of	12 months	12 months	n 12 months	3.1	3.1	91	n/a	n/a	n/a	n/a	98	98	22731	47564
3	than 12 months of	12 months	12 months	n 12 months	3.0	3.0	83	n/a	n/a	n/a	n/a	107	107	41030	21208
3	than 12 months of	12 months	12 months	n 12 months	2.4	2.4	126	n/a	n/a	n/a	n/a	107	107	24993	16081
2	2	2	2	2	2	2	138	131	171	134	126	141	134	35440	22733

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Schedule 3

Circuit	Additional context for feeders experiencing a 2025 SAIDI increase compared to qualifying baseline
04331	
01450	
25487	
04308	
04334	
04395	One-third of outage minutes are associated with a single outage caused by a fault within the Substation. Another third of outage minutes are attributed to vehicle accidents
06460	Over half of outage minutes attributed to five outage events that occurred outside of the hardened area.
01300	
65911	
23325	
26340	Nearly 70% of the minutes are attributed to a failure of a piece of equipment that was outside of the hardened area and minutes attributed to vehicle accidents
25452	
03315	Over half of outage minutes are attributed to six tree related outages events outside of the hardened area.
65937	
84385	Nearly 70% of the minutes are attributed to two outages associated with trees falling in hardening zones during a weather event. Neither outage event qualified for major storm designation. No poles were broken
47377	
05329	
06461	
01385	Two-Thirds of outage minutes occurred during four separate outage events that occurred outside of the hardened zone. One event occurred 20 minutes prior to the designation of a major storm event. Another outage was attributed to a primary cable failure.
63309	
04304	
65326	
81383	
81375	
03350	
86832	
48442	
04333	More than 50% of the outage minutes occurred during several mostly tree related outages across multiple devices outside of the hardened zones.
81350	
05358	
46320	
42495	
66404	
82355	
65497	Over 40% of outage minutes attributed to a material failure event outside of a hardened area.
05332	
81390	Approximately one-third of outage minutes are attributed to a single tree related event that occured on a tapline during a storm on July 27th, 2025.
81376	
02342	
85871	
46474	
81365	
46977	
05345	
05568	
81519	
48726	
85883	
44721	
03367	
81367	
06426	Over one-third of outage minutes are attributed to two events in the hardened areas. During one event a piece of material failed and the outage was complicated by an abnormal arrangment on the feeder. Improvements made by the MFH projects helped restore customers more quickly.
41358	Approximately 75% of the outage minutes are attributed to a single outage caused by a failure of a piece of pad-mounted equipment.
44622	

Mainfeeder Hardening

Requirement: Realized benefits compared to projected benefits. 2023 Final Order at 3

Realized Benefits 1	2021	2022	2023	2024	2025
Circuits Realized >1 Year	04331	04331, 01450, 25487, 04308, 04334, 04395 ,06460 (7)	04331, 01450, 25487, 04308, 04334, 04395, 06460, 01300, 65911, 23325, 26340, 25452, 03315, 65937, 47377, 84385 (16)	04331, 01450, 25487, 04308, 04334, 04395, 06460, 01300, 65911, 23325, 26340, 25452, 03315, 65937, 84385, 47377, 05329, 06461, 01385, 63309, 04304, 65326, 81383, 81375, 86832, 48442, 04333, 81350, 05358, 46320, 42495, 66404, 82355, 65497, 05332, 81390, 81376, 02342, 85871, 46474, 03350 (41)	04331, 01450, 25487, 04308, 04334, 04395, 06460, 01300, 65911, 23325, 26340, 25452, 03315, 65937, 84385, 47377, 05329, 06461, 01385, 63309, 04304, 65326, 81383, 81375, 86832, 48442, 04333, 81350, 05358, 46320, 42495, 66404, 82355, 65497, 05332, 81390, 81376, 02342, 85871, 46474, 03350, 04303, 81367, 81519, 44622, 81365, 46977, 48726, 44721, 05568, 06426, 85883, 03367, 41358, 05345 (55)
Critical Services Improved/Targeted >1 Year	4	40	62	118	137
Total Customers Improved/Targeted >1 Year	801	18,343	36,071	99,523	132,966
Total Miles Hardened (miles) >1 Year	2	23	91	240	320
Total Customer Interruptions Eliminated	7,557	22,058	23,902	24,009	49,990
Total Customer Minutes of Interruption Eliminated	789,887	1,142,067	4,130,777	7,505,329	6,037,790
Average Outage Minutes Before	359	323	334	306	303
Average Outage Minutes Eliminated	70	41	108	91	55
Average Outage Minutes After	289	282	226	215	248
Average Interruptions Before	3.3	2.8	2.7	2.4	2.4
Average Interruptions Eliminated	1.1	1.0	0.6	0.4	0.4
Average Interruptions After	2.2	1.8	2.1	2.0	1.9
Total Average Customer Minutes of Interruption Before (Qualifying Customers)2	593	460	504	501	495
Total Average Customer Minutes of Interruption After (Qualifying Customers)	383	365	256	224	238
Total of Qualifying Customers	604	9,110	18,118	42,967	58,416

1 Data syncronized by calander year as directed by the Commission ([PUR-2023-00051])

2 5-year baseline average

Projected Benefits (Wright Schedule 7 - PUR-2019-00154)	3-Year Total	10-Year Total
Critical Services Improved	61	428
Total Customers Improved	24,038	491,308
Total Miles Hardened (miles)	63	1,028
Total Customer Interruptions Eliminated	22,240	303,351
Total Customer Minutes of Interruption Eliminated	2,293,393	30,343,840
Average Outage Minutes Before	348	236
Average Outage Minutes Eliminated	94	61
Average Outage Minutes After	254	175
Average Interruptions Before	2.9	2.0
Average Interruptions Eliminated	1.0	0.6
Average Interruptions After	1.9	1.4

Mainfeeder Hardening – Performance During Severe Weather Events

Requirement: Provide information and data on how hardened mainfeeder sections withstand severe weather events compared to non-hardened sections of mainfeeders subject to the same severe weather event. 2023 Final Order at 3 (Report Recommendation 2, Bullet 7), 10.

The variability in major storm activity can complicate the assessment of a project's impact on performance. However, the Company regularly conducts empirical comparisons between hardened mainfeeder facilities and their non-hardened counterparts in the surrounding area. There were no major storm events in 2025 that prompted this analysis. The Company will continue to monitor these events and report on the performance of hardened mainfeeder areas during major storm events in future reports.

Schedule 6

Mainfeeder Hardening

Requirement: Report actual costs compared to estimates. 2023 Final Order at 3

Circuit	Phase	Date Complete	Estimated Cost	Actual Cost	Delta	Explanation for Increases over 15%
04331	Phase I	10/1/2020	$1,126,883	$1,251,497	11%	
01450	Phase I	3/30/2021	$429,382	$591,829	38%	Additional labor expenses associated with difficult to access facilities
25487	Phase I	11/1/2021	$4,879,326	$3,597,826	-26%	
04308	Phase I	11/25/2021	$3,340,726	$3,605,322	8%	
04334	Phase I	12/1/2021	$2,046,165	$1,670,747	-18%	
04395	Phase I	12/2/2021	$2,438,828	$2,125,315	-13%	
06460	Phase I	12/2/2021	$2,606,662	$2,307,526	-11%	
01300	Phase I	1/14/2022	$9,338,253	$9,774,670	5%	
65911	Phase I	3/8/2022	$8,336,068	$6,628,353	-20%	
23325	Phase I	4/18/2022	$7,380,230	$5,056,376	-31%	
26340	Phase I	4/18/2022	$3,142,088	$5,125,994	63%	Additional labor expenses associated with difficult to access facilities
25452	Phase III	8/31/2022	$1,665,175	$3,890,757	134%	Additional tree clearing expenses and traffic control during construction
03315	Phase III	9/27/2022	$1,054,070	$2,079,866	97%	Additional labor and materials for underground boring
65937	Phase III	10/20/2022	$1,840,672	$2,632,461	43%	Additional labor expenses associated with difficult to access facilities
84385	Phase III	11/2/2022	$2,595,530	$4,943,294	90%	Replacement of poles in difficult work terrain (rock), matting costs, and traffic control during construction
47377	Phase III	11/23/2022	$2,563,905	$2,048,012	-20%	
05329	Phase III	1/17/2023	$1,574,140	$3,446,377	119%	Congested work area required additional labor and traffic control. Many of the holes for the new poles had to be dug by hand.
06461	Phase III	2/20/2023	$1,432,963	$1,554,222	8%	
01385	Phase III	2/23/2023	$588,252	$1,696,165	188%	Additional labor expenses associated with difficult to access facilities
63309	Phase III	3/1/2023	$1,368,426	$2,865,335	109%	Additional labor expenses associated with difficult to access facilities
04304	Phase III	3/21/2023	$4,768,359	$5,796,911	22%	A scope change in the field required additional material and labor
65326	Phase III	3/29/2023	$2,096,292	$7,035,317	236%	Additional labor, material and equipment expenses due to extremely wet conditions
81383	Phase III	4/5/2023	$1,688,600	$2,241,471	33%	Increase labor cost due to traffic control and difficulty work conditions
81375	Phase III	5/2/2023	$2,355,306	$6,833,596	190%	Additional labor expenses associated with difficult to access facilities, additional tree clearing, and matting
03350	Phase III	5/30/2023	$1,637,768	$2,519,605	54%	Wet field conditions required additional matting, materials and labor
86832	Phase III	6/15/2023	$2,487,698	$4,338,355	74%	Additional design and material cost associated with difficult to access facilities. Poles were located on a mountain and in rock
48442	Phase III	6/20/2023	$2,384,868	$9,799,159	311%	Additional labor expenses associated with difficult to access facilities, additional tree clearing, and matting
04333	Phase III	6/29/2023	$7,391,460	$10,203,516	38%	Additional labor and materials due to difficult to access work locations
81350	Phase III	7/24/2023	$1,451,443	$4,100,506	183%	Additional labor expenses associated with difficult to access facilities, additional tree clearing, and matting
05358	Phase III	7/24/2023	$643,188	$1,085,176	69%	Additional tree clearing expenses were required
46320	Phase III	7/26/2023	$878,017	$959,108	9%	
42495	Phase III	8/2/2023	$1,548,360	$1,852,377	20%	Additional matting and Park Service permits were required
66404	Phase III	8/7/2023	$1,064,397	$1,393,001	31%	Additional labor expenses associated with difficult to access facilities, additional tree clearing, and matting
82355	Phase III	8/28/2023	$2,995,622	$4,453,091	49%	Additional labor expenses associated with difficult to access facilities, additional tree clearing, and traffic control
65497	Phase III	9/19/2023	$1,589,854	$2,625,656	65%	Additional labor expenses associated with difficult to access facilities. Wet field conditions required additional matting.
05332	Phase III	10/3/2023	$1,592,379	$3,835,024	141%	Wet field conditions required additional matting
81390	Phase III	11/3/2023	$2,871,196	$3,713,036	29%	Additional labor expenses associated with difficult to access facilities. Additional tree trimming was also required.
81376	Phase III	11/30/2023	$2,170,370	$3,893,875	79%	Additional labor expenses associated with difficult to access facilities. Additional tree trimming was also required.
02342	Phase III	12/4/2023	$2,700,244	$4,441,134	64%	Additional labor expenses associated with difficult to access facilities
85871	Phase III	12/7/2023	$2,024,814	$3,147,202	55%	Additional labor expenses associated with difficult to access facilities, additional tree clearing, and matting
46474	Phase III	12/22/2023	$734,949	$1,606,500	119%	Increase labor cost due to traffic control , difficulty in work condition
81365	Phase III	1/16/2024	$1,005,398	$2,304,137	129%	Increased labor cost due to reconditioning, difficult terrain, tree trimming
46977	Phase III	3/5/2024	$1,119,838	$3,047,117	172%	A scope change required steel poles to be installed in the field. This caused an increase in labor, material and matting.
05345	Phase III	3/15/2024	$2,176,434	$5,575,506	156%	Wet field conditions required additional matting, materials and labor. Additional traffic control was also required.
05568	Phase III	4/1/2024	$1,208,366	$2,808,198	132%	Additional labor expenses associated with traffic control
81519	Phase III	4/9/2024	$4,820,636	$9,044,055	88%	Increased labor cost due to reconditioning, difficult terrain, tree trimming
48726	Phase III	5/21/2024	$2,696,681	$5,383,768	100%	Difficult to access work locations, additional tree clearing, and traffic during construction, matting
85883	Phase III	5/21/2024	$1,704,487	$5,057,280	197%	Increased labor cost due to reconditioning, difficult terrain, tree trimming
44721	Phase III	6/27/2024	$5,323,292	$8,425,225	58%	Increased labor hours and traffic control due to complexity of work on a double circuit pole line
03367	Phase III	8/28/2024	$3,129,335	$3,792,886	21%	A field change due to environmental concerns requried additional matting and tree trimming to complete the project
81367	Phase IIIB	11/7/2024	$4,392,456	$3,716,183	-15%	
04303	Phase IIIB	11/13/2024	$1,475,062	$1,298,409	-12%	
06426	Phase III	11/21/2024	$1,785,780	$3,036,974	70%	Environmental permitting required an increase in matting, labor and material
41358	Phase IIIB	12/17/2024	$4,593,061	$4,359,583	-5%	
44622	Phase III	12/20/2024	$4,651,152	$11,338,537	144%	Increase labor cost due to traffic control & tree trimming.
02318	Phase III	4/30/2025	$2,859,748	$5,331,767	86%	Increase labor cost - UG work and permitting
66401	Phase III	6/10/2025	$4,912,815	$2,580,823	-47%	
63320	Phase IIIB	12/10/2025	$43,649,441	$28,033,010	-36%	

Schedule 7

Mainfeeder Hardening and Tree Overhang Removal Pilot

Requirement: Report which mainfeeders were subject to both mainfeeder hardening and targeted corridor improvement tree overhang removal pilot. 2023 Final Order at 10

There are zero sections of mainfeeders faciliites that are concurrently subject to both mainfeeder hardening and the targeted corridor improvement tree overhang removal pilot. Tree overhang pilot removal was performed on two mainfeeder hardening circuits, but it was performed after the feeders were hardened and in a different location along the feeder. Activities within these programs are distinct and managed independently.

Targeted Corridor Improvement Hazard Tree Pilot

Requirement: Comply with the proposed hazard tree pilot reporting metrics with the modification to count the number of areas artificial intelligence has identified and how many of those areas include at least one hazard tree.

Artificial intelligence has identified hazard tree polygons with approximately 78% accuracy on 3-span segments in the pilot office of Charlottesville. Within these segments, the vendor was able to identify at least one hazard tree in each polygon flagged by the model.

Voltage Island Mitigation

Requirement: Track and report the measurable benefits of the voltage island mitigation projects. 2021 Final Order at 15, 22.

For completed voltage island mitigation projects, any long-duration outages that are mitigated will be detailed in future annual reports, as they occur. No such events have occurred to date.

How Grid Technologies Projects Support Integrated Planning

Requirement: Provide information on how each Grid Technologies project will support integrated planning at the distribution system level and how such information will be used to inform the Company's next Integrated Resource Plan. 2021 Final Order at 21-22.

In September 2019, Dominion Energy Virginia presented the Commission with initial details on the need to transform not only the distribution grid, but also to transform how distribution grid planning occurs. Specifically, the Company presented a white paper that provided a conceptual first look at its transition toward integrated distribution planning ("IDP").[1] In June 2021, the Company provided an update that highlighted notable successes in the evolution toward IDP and noted that the Company had begun to work to create a roadmap for IDP that will add tangible goals and timeframes to IDP maturity, with the intention of presenting the roadmap in 2023.[2] In March 2023, the Company presented that roadmap (the "2023 IDP Roadmap") as part of its request for a prudence determination for Phase III of the Grid Transformation Plan.[3] In October 2024, the Company updated its 2024 IDP Roadmap as part of its 2024 Integrated Resource Plan (the "2024 IRP").[4]

How Grid Technologies Projects Support IDP

The Company defines IDP as a consolidated process to address the capacity, performance, reliability, resilience, and distributed energy resource ("DER") integration needs of the distribution grid. See the 2023 IDP Roadmap for details on the transition to IDP.

The grid technologies projects approved by the Commission as part of the GT Plan support IDP in many ways. For example, intelligent grid devices and substation technology deployment will provide the additional granularity of data along distribution feeders and at more frequent intervals throughout the year that is necessary to enable precise modeling and engineering analyses. These projects also provide situational awareness and, paired with advanced systems such as the distributed energy management system ("DERMS"), fault, location, isolation and service restoration ("FLISR") software, and an outage management system ("OMS") provide the necessary control capabilities to ensure safe and reliable grid operation with the growing adoption of DER resulting in bi-directional power flows and dynamic voltages. These same equipment and systems also ensure grid availability to move energy along the distribution grid for DER serving as a non-traditional grid solution.

Similarly, the enterprise asset management system ("EAMS") and remote sensing, image management and analytics program ("iMAP") will provide more efficient data collection and insight of asset conditions and performance, improving grid reliability, resiliency, and availability for customer loads and DER by driving improved decisions related to equipment specifications, maintenance, and replacements. The Company's hosting capacity analysis supports customers assessing costs and benefits of connecting DER on the grid by indicating how much DER can be connected at a specific location while minimizing adverse impacts to the grid and upgrade costs. The non-wires alternative ("NWA") pilot will permit the Company to continue to explore NWA. An NWA is a grid project that uses non-traditional transmission and distribution solutions, such as distributed generation, energy storage, and grid software and controls, either individually or in concert (*e.g.*, a microgrid), to address distribution system needs and defer or avoid implementing conventional infrastructure (*i.e.*, "wires") investments.

[1] Case No. PUR-2019-00154, 2019 GT Plan Document at 14-15.

[2] Case No. PUR-2021-00127, 2021 GT Plan Document at 12-13.

[3] Case No. PUR-2023-00051, 2023 GT Plan Document at 11-12, Appendix C.

[4] Case No. PUR-2024-00184, 2024 Integrated Distribution Planning Roadmap, Appendix 3N.

The list below provides a short synopsis on each grid technologies project:

- Intelligent Grid Devices. Intelligent grid devices provide granular data along the feeder that is necessary for more precise modeling and analysis of load flows and DER outputs. Intelligent grid devices, in conjunction with FLISR, also provide situational awareness and control capabilities to improve grid reliability, resiliency, and availability.
- FLISR. FLISR, in conjunction with intelligent grid devices, provides situational awareness and control capabilities to improve grid reliability and resiliency and support availability of DER as a grid resource while enabling customers to maximize the benefits of their DERs.
- DERMS. DERMS provides situational awareness and control capabilities for different types of DER to optimize grid operation and maximize customer benefits as these non- traditional solutions are integrated.
- Hosting Capacity Analysis. Hosting capacity analysis supports the integration of DER by indicating the available capacity for DER to interconnect to the distribution grid while minimizing upgrades needed to avoid adverse grid impacts.
- EAMS. EAMS provides more granular insight of asset conditions and performance, driving improved decision making related to equipment specifications, maintenance, and replacement that improves grid reliability and resiliency and supports availability of DER as a grid resource while enabling customers to maximize the benefits of their DERs.
- Voltage Optimization Enablement. Voltage optimization enablement projects, in conjunction with an advanced voltage control system, enable implementation of a demand-side management program to lower energy consumption and demand, directly reducing resource needs with no discernible impact to most customers. This capability also has the potential to serve as a non-traditional solution for grid constraints.
- Substation Technology Deployment. Similar to intelligent grid devices, substation technology deployment provides granular data that is necessary for more precise modeling of load flows and DER outputs. Substation technology deployment also provides situational awareness and control capabilities to support grid reliability, resiliency, and availability.
- Locks Campus Microgrid. The Locks Campus Microgrid demonstration project will provide valuable real-world data to understand how microgrids and DER interact with the distribution grid, what capabilities, monitoring, and controls are necessary for safe and reliable operation, and how they can be leveraged for grid resiliency and potentially as non-traditional solutions.
- NWA Pilot. The application of NWAs is a component within the 2023 IDP Roadmap. The NWA pilot will establish a process for evaluating and implementing non-wires alternative solutions across the Company's distribution grid, focusing initially on energy storage solutions.
- OMS. An OMS is a centralized software solution and associated infrastructure for the purpose of analyzing and managing outage events on the distribution system. It uses field information and notifications from customers to identify outage events, create and manage restoration work requests, and provide restoration information to customers. An OMS is essential to utility operations.
- iMAP. Remote sensing involves gathering information about the company's electric distribution assets using digital technology without physical contact. This includes data from LiDAR, aerial and ground inspection images, high-resolution ortho imagery, radiometric thermal imaging, video, and satellite images. Historically, the company has relied on in-person inspections and manual reports for preventive maintenance and damage assessment. However, the volume of image data has increased significantly, and the current system lacks a platform for efficient data storage, management, and access. This limitation hinders the company's ability to make data-driven decisions. To address this, the company proposes creating a Remote Sensing based Image Management and Analytical Program (iMAP) for its Electric Distribution organization.

How Information from Grid Technologies Projects Will Inform the 2025 Integrated Resource Plan

The Company's transition to IDP is a gradual process that requires the deployment of various Grid Technologies projects approved by the Commission, along with other essential processes and capabilities. While these projects will provide immediate benefits in terms of improved reliability, resilience, and availability for customers and connected DERs, the Company is still in the process of deploying these Grid Technologies. Once complete and integrated, the Company will be able to fully utilize the enhanced information and advanced analytics offered by these Grid Technologies to expand IDP and inform future Integrated Resource Plans. The IDP Roadmap outlines tangible goals for the near-term components of Grid Technologies, while establishing a clear path forward for long-term benefits.

In summary, Grid Technologies play a pivotal role in enhancing the Company's distribution grid by providing precise data, situational awareness, and control capabilities. These advancements support the integration of DERs, improve grid reliability and resilience, and explore non-traditional grid solutions. As the Company continues its transition to IDP, these technologies will be instrumental in achieving the long-term vision of a modern, efficient, and resilient distribution *grid. The ongoing efforts and strategic planning outlined in the IDP Roadmap ensure that the Company is well-prepared to meet future challenges and opportunities in the evolving energy landscape.*

Schedule 11

Intelligent Grid Devices and FLISR

Requirement: Include the Company's planned and actual costs and reliability improvements for the feeder segments on which intelligent grid devices and FLISR are deployed. 2021 Final Order at 19, 22.

The Company has provided planned and actual costs for the feeder segments on which intelligent grid devices have been deployed. The Company will provide reliability improvement data once FLISR has been deployed.

IGD Circuit	Completion Date	Planned Cost	Actual Cost *through December 31, 2025*
01451	5/6/2022	$86,125	$95,618
01480	9/7/2022	$62,938	$69,021
02805	4/20/2022	$203,203	$237,603
04303	10/24/2022	$1,113,460	$1,097,316
04334	2/24/2022	$69,894	$51,458
05330	10/10/2022	$199,688	$323,399
05351	9/20/2022	$150,096	$137,420
22371	5/3/2022	$74,694	$61,876
23462	3/21/2022	$111,428	$97,991
26470	2/21/2022	$101,353	$114,939
28428	3/15/2022	$59,719	$68,275
28466	3/11/2022	$84,105	$61,930
41436	4/21/2022	$80,004	$81,770
41914	8/24/2022	$336,394	$424,412
42340	10/1/2022	$984,918	$1,327,886
44710	7/21/2022	$222,510	$401,196
46772	3/24/2023	$116,948	$142,554
46825	3/7/2022	$79,279	$140,521
47698	11/2/2022	$170,193	$268,153
48330	7/28/2022	$222,410	$326,624
48666	8/25/2022	$342,860	$418,416
48718	5/27/2022	$75,163	$71,501
48719	3/16/2022	$123,863	$136,486
46742	1/5/2023	$241,354	$439,667
41862	2/14/2023	$245,550	$343,976
82406	4/25/2023	$140,859	$216,231
25365	5/18/2023	$310,745	$315,686
41854	8/16/2023	$232,485	$332,737
81305	9/27/2023	$293,518	$293,415
82409	5/2/2024	$994,806	$2,127,269
41435	7/24/2024	$650,282	$870,425
41489	6/25/2025	$90,000	$84,099
44619	2/27/2025	$180,000	$183,565

Dominion Energy Virginia
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Schedule 12 - DERMS

Requirement: Report on the various uses of DERMS, including visibility of DERs across its system and the Company's ability to leverage DER smart inverter functionalities to provide grid support. 2021 Final Order at 20, 22.

Dominion Energy's Distributed Energy Resource Management System (DERMS) is used as a centralized platform to manage distributed energy resources (DERs) and associated programs by unifying the monitoring, visualization, and control of DERs. The DERMS platform addresses all types of DERs, including electric school buses, electric vehicles (EVs), small and large distributed generation interconnections, existing and future demand-side management (DSM) programs, and energy storage systems. The Company's DERMS platform is scalable, flexible, and capable of expanding with the increased rate of DER adoption. DERMS went live in Q3 2025 with Stage 1 and Stage 2 capabilities, enabling the following use cases:

Visibility:

1. Monitor the sites in real-time: Receive real-time telemetry including real-time and reactive power, voltages, frequency and grid connectivity status for utility-scale front-of-the-meter and behind-the-meter DERs. The statuses will indicate if the Solar PV systems are online and sending data to DERMS.
2. Forecasting
    a. Solar generation forecasting for DER assets. Forecasted weather data will be used to inform the predicted power output of the Solar PV systems.
    b. Forecasting can be performed at a site-level or for an aggregate group of assets at the fleet-level
3. Baselining
    a. Calculate the baseline performance for the DER sites at site-level and for an aggregated group of assets at the fleet-level
4. Visibility into the upcoming and past events scheduled for Smart Thermostat groups and Electric Vehicle chargers
5. Manage DER Assets in a centralized platform that displays the name plate asset details and grid information

DER Dispatch:

1. Ability to call Smart thermostat groups and all-call events using open ADR protocol to reduce the system load
2. Ability to call All call EV chargers events using open ADR protocol to reduce the system load

3. DER grouping is available for different objectives to help achieve utility or grid objectives depending upon the program's goals.
    a. Energy control
    b. Power control
    c. Reactive control
    d. Demand Response
4. Control Battery (BESS) setpoints
    a. Dispatch Battery (BESS) Pilots for Power Control. Power control for BESS pilots will allow offsetting transformer loads during peak demand by discharging BESS pilots and consume excess solar production by charging BESS pilots
    b. Dispatch Battery (BESS) Pilots for Reactive Power Control. Reactive power control for BESS pilots will allow using the BESS pilots to contribute to local voltage constraint mitigation.
    c. Dispatch Battery (BESS) Pilots for Energy Control. Energy control for BESS pilots will allow for managing the state of charge for battery systems.

Reporting:

1. Health asset report available to monitor the health of program assets using this Report. By proactively identifying assets that are unavailable (for example, due to opt-out status, or perhaps poor connectivity)
2. Demand response event report includes summaries of Event performance. Displays include a graphical representation of the number of assets controlled in a selected Event. Users can also select a specific event to see a breakdown of how delivered capacity and energy varied throughout the duration of the event, as well as the setpoint sent to each dispatched Asset.
3. Event overview report to view a list of upcoming Concerto Events, those in progress, or for a quick view of previously scheduled Events. Scheduled control time will be tabulated on screen. Event reservations as well as past performances are a click away.
4. Operational data reports enable a variety of offline analysis activities, including performance evaluation, or data collection for measurement and verification of workflows.

Notification and Alarms:

1. DERMS has the capability to provide notifications about scheduled events when Assets (or an aggregation of their Assets) are to provide capacity or to participate in grid service functions. Reminders can be sent as email, SMS (text), and/or IVR (phone).
2. Alarms configuration is available for DER assets to provide alarm notifications to key stakeholders that will support these assets on alarms such as voltage thresholds, loss of communication, etc.

DER Smart Inverter:

DERMS is also capable of leveraging DER smart inverter functionality for grid support such as voltage regulation, reactive power control, through its group dispatch capabilities. Current efforts are focused on architectural design and evaluation of technical approaches to enable inverter setpoints, with the use of a DER Gateway identified as a potential option to support IEEE 1547-compliant inverter functions and future communications frameworks. The DERMS team has identified a Dominion Energy–owned site to serve as a pilot for enabling and validating smart inverter functionality. To advance this capability, two key process areas have been identified: (1) amending interconnection agreements to allow smart inverter functionality, and (2) defining the appropriate interconnection studies required to support these capabilities. These activities are intended to position the Company to leverage smart inverter functionality in subsequent DERMS phases, enabling enhanced grid support once system integration, testing, and operational readiness are achieved.

Schedule 13

Voltage Optimization Enablement

Project Type Completed (list all types, verify from testimony)	Planned Number of Defects	Actual Number of Defects	Planned Avg Cost/Defect	Actual Avg Cost/Defect
Txfmr/Service	7,415	7,463	$5,200	$3,409
Primary Conversion	2,400	3,137	$10,000	$9,202
Substation				

represents VO upgrade projects completed as of December 31, 2025

Non-wires Alternative (NWA) Pilot

Requirement: Report on progress in working with Staff to develop a metrics list for the non-wires alternative pilot.

Key items addressed:

• Process Development and Project Screening

The Company has completed the process development and training necessary for the System Planning team to identify potential projects for inclusion in the NWA Program. Current analyses indicate that battery solutions continue to exceed the cost of traditional system upgrades. The team will continue evaluating projects that meet the established criteria as they progress into detailed technical and economic assessments for possible program inclusion.

• Pilot Ownership Models

The pilot will be used to gain experience across multiple ownership structures, including:

•Dominion-owned,
•Developer build/transfer, and
•Power Purchase Agreements (PPA).

Staff support deploying projects across all ownership models, with the first pilot focused on a Dominion owned installation. Staff also agreed to the proposed use of the Tesla Megapack based on its strong performance and reliability demonstrated during the GTSA pilot, which helps ensure unit availability during peak periods. Dominion Energy, based on the results of the previously referenced technical and economic assessments, agrees with Staff's assessment regarding the technology's availability and reliability.

• Future NWA Solution Evaluation

The Company will begin evaluating additional non-wires solutions for broader program integration that allow greater flexibility. Examples include residential BESS aggregation and mobile BESS resources, which may offer additional flexibility and cost-effective alternatives to traditional infrastructure upgrades.