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PREFILED STAFF TESTIMONY

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

PUR-2021-00127

September 24, 2021

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PART A

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PRE-FILED TESTIMONY

OF

MICHAEL A. CIZENSKI

VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUR-2021-00127

SEPTEMBER 24, 2021

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Summary of Direct Testimony - Michael A. Cizenski

My testimony addresses Virginia Electric and Power Company d/b/a Dominion Energy Virginia's ("Company") third petition for approval of a plan for electric distribution grid transformation projects ("GT Plan"). The Company is requesting approval of Phase II of the GT Plan which includes investments to be made from 2022 through 2023.

Staff evaluated the Company's proposal for Phase II based primarily on guidance found in the Commission's Final Orders in the Company's 2018 and 2019 GT Plan proceedings. As addressed herein and in the testimonies of Staff's other witnesses, Staff:

1. Supports approval of the Company's Phase II proposals for a customer information platform; grid infrastructure program; intelligent grid devices and FLISR (fault location, isolation, and service restoration); enterprise asset management system; telecommunications; and physical and cyber security.
2. Does not oppose approval of the Company's Phase II advanced metering infrastructure ("AMI") proposal, should the Commission determine that the Company has sufficiently addressed the Commission's previous concerns regarding AMI deployment.
3. Opposes approval of the Company's Phase II proposals for substation technology deployment and distributed energy resources management system.
4. Takes no position on the Company's Phase II proposal for voltage optimization enablement.

As Staff witness Clayton explains, the Company's Phase II cost estimates are detailed and supported by requests for proposals, vendor quotes, existing contracts, engineering analysis, and design plans.

Staff's consultant Volkmann explains that the Company's claim of an urgent need to modernize its grid due to distributed energy resource ("DER") growth is exaggerated.

Staff witness Lohmeyer discusses the Company's response to the Commission's directives regarding customer bill format and provides alternatives for the Commission consideration.

In addition, my testimony evaluates certain aspects of Phase II of the GT Plan and concludes as follows:

- The Company's Phase II Petition includes a deployment plan for system-wide time-varying rates.
- Staff has significant concerns relative to the Company's ability to efficiently process the anticipated influx of DER interconnection requests necessary to both take advantage of the Company's proposed GT Plan Grid Technologies and meet the mandates of the Virginia Clean Economy Act.
- The Company's proposed implementation of Phase II appears to be consistent with the principles of the Virginia Environmental Justice Act.

Finally, should the Commission approve the Grid Technologies components as being necessary to support increased DER penetration, I make several recommendations for the Commission's consideration.

PRE-FILED TESTIMONY

OF

MICHAEL A. CIZENSKI

VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUR-2021-00127

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

A. My name is Michael A. Cizenski. I am a Principal Utilities Engineer in the Commission's Division of Public Utility Regulation.

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

A. My testimony addresses certain aspects of Virginia Electric and Power Company d/b/a Dominion Energy Virginia's ("Dominion" or "Company") petition ("Petition") for approval of Phase II of the Company's plan for electric distribution grid transformation projects ("GT Plan" or "Plan"). In particular, my testimony presents:

1. A summary of Staff's combined recommendations regarding Phase II of the Plan;
2. Staff's evaluation of Phase II of the GT Plan based on guidance provided in the Commission's Final Order in the 2019 GT Plan proceeding, Case No. PUR-2019-00154.[1]
3. An assessment of: Advanced Metering Infrastructure ("AMI"); Grid Infrastructure; Grid Technologies, Physical Security; and Environmental Justice.

[1] *See 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, Doc. Con. Cen. No. 200330188, Final Order (Mar. 26, 2020) ("2019 GT Plan Final Order").

In all cases where appropriate, I will also provide recommendations to the Commission.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

I. Introduction of Staff Witnesses
II. Overview of the Petition
III. Findings and Conclusions
IV. Staff's Evaluation of Phase II of the GT Plan
V. Assessment of Selected GT Plan Components and Compliance with Environmental Justice Principles

I. INTRODUCTION OF STAFF WITNESSES

Q. PLEASE INTRODUCE THE OTHER STAFF WITNESSES PRESENTING TESTIMONY IN THIS PROCEEDING.

A. Staff presents the testimony of three other witnesses, as follows:

Mr. Curt Volkmann, President and founder of New Energy Advisors, LLC provides an assessment of:

- The state of distributed energy resources ("DER") deployment in the Company's service territory and Dominion's DER interconnection performance.
- The Company's Phase II GT Plan compared with well-developed grid modernization plans in other jurisdictions.
- The Company's proposed Grid Technologies and Telecommunications projects.

Tyler Lohmeyer, a Utilities Analyst in the Division of Public Utility Regulation:

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- Discusses the Company's response to the Commission's directives relative to customer bill format from the Final Order in Case No. PUR-2020-00035;[2]
- Provides background on the issue of customer bill transparency; and
- Provides alternative, interim customer bill format options for the Commission's consideration.

Anna L. Clayton, a Principal Utility Specialist in the Division of Utility Accounting and Finance:

- Discusses the Company's proposed total Phase II lifetime revenue requirement;
- Discusses the supporting detail, by project, for Phase II cost estimates;
- Provides the lifetime revenue requirements associated with Substation Technology Deployment and Distribution Energy Resource Management System projects.

II. OVERVIEW OF THE PETITION

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY'S PETITION.

A. On June 21, 2021, the Company filed for approval of the GT Plan pursuant to § 56-585.1 A 6 of the Code of Virginia ("Code"). Specifically, the Company is requesting approval of Phase II of its ten-year plan to transform its electric distribution grid. These Phase II investments consist of proposed projects in 2022 and 2023. This is the Company's third petition for approval of a GT Plan. In 2018, in Case No. PUR-2018-00100, the Company filed its first petition. In that proceeding, the Commission approved certain proposed Phase I investments related to cyber and physical security, including supporting

[2] *See Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code §§ 56-597 et seq.*, Case No. PUR-2030-00035, Doc. Con. Cen. No. 210210007, Final Order (Feb. 1, 2021) ("2020 IRP Final Order").

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telecommunications infrastructure, which the Company refers to as "Phase IA" of the GT Plan.[3] The Commission denied the remaining Phase IA portions of the GT Plan without prejudice, citing a lack of detailed cost estimates and other concerns. The Company filed its second petition in 2019, in Case No. PUR-2019-00154. In that proceeding, the Commission approved the Company's planned "Phase IB" investments related to cyber security, stakeholder engagement and customer education, the customer information platform ("CIP"), pilot programs and hosting capacity analysis, and certain components of grid hardening. The Commission found that the Company had not proven the reasonableness and prudence of the Phase IB portion of the GT Plan or the costs associated with AMI, the self-healing grid and related investments, and certain components of grid hardening.

The ten-year GT Plan, as proposed in this proceeding, includes nine components: (1) AMI; (2) CIP; (3) grid infrastructure; (4) grid technologies; (5) physical security; (6) transportation electrification;[4] (7) telecommunications infrastructure; (8) cyber security; and (9) stakeholder engagement and customer education. The total ten-year GT Plan consists of $2.88 billion of capital investment and $345.3 million of operation and maintenance ("O&M") expenses. Phase II includes portions of all of the above components, except transportation electrification, and consists of $669.4 million of capital investment and $109.5 million of O&M expenses. The following table summarizes the proposed cost of the GT Plan, excluding financing costs, by component:

[3] *See 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-2018-00100, Doc. Con. Cen. No. 190130074, Final Order (Jan. 17, 2019) ("2018 GT Plan Final Order").

[4] Also known as the Smart Charging Infrastructure Pilot Program ("Smart Charging Pilot").

Table 1
Company Proposed Cost of GT Plan
(in millions of dollars)

	Phase II		Total GT Plan	
	Capital	O&M	Capital	O&M
Advanced Metering Infrastructure (AMI)	$186.1	$12.2	$392.6	$53.1
Customer Information Platform (CIP)	$139.1	$68.8	$232.9	$157.3
Grid Infrastructure	$11.4	$16.3	$761.9	$38.5
Grid Technologies	$192.3	$2.1	$1,035.4	$14.3
Physical Security	$37.3	$0.2	$143.9	$6.8
Transportation Electrification	-	-	$5.9	$15.5
Telecommunications	$97.9	$4.1	$289.5	$29.6
Cyber Security	$5.3	$2.8	$16.0	$19.3
Customer Education	-	$3.0	-	$11.0
Total	**$669.4**	**$109.5**	**$2,878.1**	**$345.3**

Staff witness Clayton provides further details on the Phase II GT Plan costs and lifetime revenue requirements in her testimony.

Q. PLEASE IDENTIFY THE LANGUAGE IN CODE § 56-585.1 A 6 THAT SETS THE STANDARD FOR COMMISSION REVIEW OF THE GT PLAN.

A. Code § 56-585.1 A 6 states as follows relative to the Commission's standard for review of petitions for 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.

Code § 56-585.1 A 6 further provides that "[e]lectric distribution grid transformation projects are in the public interest."

III. FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE STAFF'S OVERALL RECOMMENDATIONS TO THE COMMISSION REGARDING THE COMPANY'S PETITION.

A. As explained in greater detail below and in the testimonies of Staff witnesses Lohmeyer and Clayton, and Staff's consultant Volkmann, Staff investigated and analyzed the Company's Petition based on the guidance provided by the Commission in the 2018 and 2019 GT Plan Final Orders. The following table summarizes Staff's recommendations to the Commission on Phase II of the GT Plan:

Table 2

Staff Recommendations on Phase II of the GT Plan

Phase II Component	Staff Recommendation	Reason for Recommendation	Witness
Advanced Metering Infrastructure (AMI)	Should the Commission determine that the Company has sufficiently addressed the Commission's previous concerns regarding AMI deployment, Staff does not oppose approval of the AMI component.	The Company has provided a plan for system-wide time varying rates which coincides with the deployment of both AMI and CIP.	Cizenski
Customer Information Platform (CIP)	Supports approval	The Phase II CIP proposal is a continuation of reasonable and prudent spending whose costs are supported by multiple vendor agreements.	Cizenski,
Grid Infrastructure	Supports approval	The ash tree mortality and the herbicide programs are consistent with previously approved programs and the costs are based on existing contracts. The Company's four voltage island mitigation projects are consistent with those projects approved in Phase IB.	Cizenski
Intelligent Grid Devices + FLISR	Supports approval	Limited scope in Phase II can demonstrate expected reliability improvements while improving situational awareness	Volkmann
Voltage Optimization Enablement	No position	VO Enablement has high capital costs, can result in energy and demand savings for Dominion's customers, however it is unclear if the benefits exceed the costs.	Volkmann
Enterprise Asset Management System (EAMS)	Supports approval	EAMS is a foundational technology that will enhance safety and reliability while positioning the Company for accelerating DER growth.	Volkmann

Substation Technology Deployment	Opposes approval	The Company's claimed need to urgently modernize its grid due to DER growth is exaggerated, and the proposed Phase II substation technology deployment is premature.	Volkmann
DER Management System (DERMS),	Opposes approval	With the Company's current relatively low DER penetrations, the majority of its distribution system able to safely and reliably accommodate higher DER penetrations, and the uncertainty of requirements from PJM's FERC Order 2222 compliance filing, the Company's proposed implementation of a DERMS in Phase II is premature.	Volkmann
Physical Security	Supports approval	The Phase II physical security is a continuation of reasonable and prudent spending which is based on detailed cost estimates and incorporates lessons learned from Phase IA.	Cizenski
Telecommunications	Supports approval	The Commission previously approved Dominion's Tier 1 and Tier 2 telecommunications in GT Plan Phase I.	Volkmann
Cyber Security	Supports approval	The Phase II cyber security is a continuation of reasonable and prudent spending which is based on detailed cost estimates.	Cizenski
Customer Education	Supports approval for those costs associated with approved components	Staff continues to support approval of reasonable costs for customer education	Cizenski

Q. WHAT ARE THE FINDINGS AND CONCLUSIONS INCLUDED IN YOUR TESTIMONY?

A. My primary findings and conclusions relative to the Company's GT Plan are as follows:

1) In response to Commission guidance provided in the 2019 GT Plan Final Order with respect to the deployment of AMI, the Company's Phase II Petition includes a plan for system-wide time-varying rates in this Petition, starting in 2025, following the new CIP going into service and the full deployment of AMI. The Company has also obtained Commission approval of Schedule 1G, a voluntary experimental time-of-use rate available to a limited number of customers. Schedule 1G became available in January 2021 and the first annual report is required to be filed by December 31, 2021.

2) Staff has significant concerns relative to the Company's ability to efficiently process the anticipated influx of DER interconnection requests necessary to both take advantage of the Company's proposed GT Plan Grid Technologies and meet the mandates of the Virginia Clean Economy Act ("VCEA").

3) Based on the evidence provided, the Company's proposed implementation of Phase II appears to be consistent with the principles of the Virginia Environmental Justice Act.[5]

Q. WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION?

A. I make the following recommendations in my testimony:

1. Should the Commission determine that the Company has sufficiently addressed the Commission's previous concerns regarding AMI deployment, Staff does not oppose approval of the AMI component proposed in Phase II of the GT Plan.
2. If the Commission approves the Grid Technologies components as being necessary to support increased DER penetration, Dominion should be required to:
   - Provide a public interconnection queue hosted on the Company's website and updated monthly;
   - Upgrade the Company's Hosting Capacity Analysis to include additional feeder information such as feeder number, substation name serving the feeder, voltage, and existing and queued generation capacity.
   - Provide a Unit Cost Guide for DER developers so that they may better understand potential interconnection cost impacts.

[5] Code § 2.2-234 *et seq.*

3. The Company should submit, upon completion, the results of its third-party environmental justice[6] evaluation of the Phase II grid transformation projects which require physical work in communities.

IV. STAFF'S EVALUATION OF PHASE II OF THE GT PLAN

Q. DID THE COMMISSION PROVIDE GUIDANCE IN THE 2019 GT PLAN FINAL ORDER?

A. Yes. The Commission's 2019 GT Plan Final Order organized the Company's proposal into the following categories of related elements:

1. AMI;
2. Cyber security and stakeholder engagement and customer education;
3. The customer information platform ("CIP");
4. Pilot programs and hosting capacity analysis;
5. Grid hardening; and
6. The self-healing grid and related investments.

In analyzing the Company's proposed Phase II of the GT Plan, Staff relied in part on the guidance in the Commission's 2019 GT Plan Final Order. Below is a summary of the guidance provided in the 2019 GT Plan Final Order, by category, and Staff's conclusions regarding Phase II of the GT Plan based on this guidance. The Company has also proposed additional Physical Security programs as part of Phase II of the GT Plan. For the Physical

[6] For purposes of this testimony, Staff uses the definition of environmental justice as found in the Code of Virginia § 2.2-234 – "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." "Environment" is further defined in that section as "the natural, cultural, social, economic, and political assets or components of a community."

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Security Component, Staff relied in part on guidance found in the Commission's 2018 GT Plan Final Order.

AMI

Q. WHAT FINDINGS OR GUIDANCE DID THE COMMISSION PROVIDE RELATIVE TO AMI IN THE 2019 GT PLAN FINAL ORDER?

A. The Commission found that "the Company has simply not provided a concrete, definitive plan to implement time of use rates on a system-wide basis and bring the benefits of full AMI deployment to customers in a timely manner. Accordingly, we once again find the Petition contains an insufficient plan to maximize the potential of AMI, and that the substantial cost to customers of AMI is not reasonable and prudent based on the record established herein. Once again, this rejection is without prejudice".[7]

Q. BASED ON THIS GUIDANCE, WHAT IS STAFF'S POSITION ON THE COMPANY'S PROPOSED AMI PROGRAM?

A. Based on the specific guidance provided by that Commission Final Order, I believe the Company has complied to some extent. As discussed in further detail later in my testimony, the Company has provided a plan to implement time of use rates on a system-wide basis. Should the Commission determine that the Company has sufficiently addressed the Commission's previous concerns regarding AMI deployment, Staff does not oppose approval of the AMI component.

[7] 2019 GT Plan Final Order at 9 (internal footnotes omitted).

Cyber Security and Stakeholder Engagement and Customer Education

Q. ARE THERE PHASE II COST CATEGORIES THAT WOULD FIT UNDER THE 2019 GT PLAN FINAL ORDER CYBER SECURITY AND STAKEHOLDER ENGAGEMENT AND CUSTOMER EDUCATION CATEGORIES?

A. Yes. In Phase II, the Company is proposing costs for: Cyber Security ($5.3 million in capital costs and $2.8 million in O&M costs); and Customer Education ($3.0 million in O&M costs), which fit under these categories.

Q. WHAT GUIDANCE DID THE COMMISSION PROVIDE FOR CYBER SECURITY IN THE 2019 GT PLAN FINAL ORDER?

A. The Commission found that:

> No party specifically took issue with the Company's proposed Phase IB cyber security component, and the Commission generally supports reasonable utility spending to support enhanced utility security.[8] Consistent with our determination in the 2018 Grid Mod Final Order, the Commission finds reasonable and prudent the costs of the Company's proposed Phase IB cyber security program, with the exception of the proposed spending that is related exclusively to components of the Plan that are not approved herein.[9]

Q. BASED ON THIS GUIDANCE, WHAT IS STAFF'S POSITION ON THE COMPANY'S PROPOSED PHASE II CYBER SECURITY PROGRAM?

A. Staff believes that the proposed Phase II cyber security is a continuation of reasonable and prudent spending to support enhanced utility security which the Company states are extensions or separate rollouts of existing Company cyber security solutions. Accordingly, Staff supports approval of the Company's Phase II cyber security program.

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[8] 2018 GT Plan Final Order at 7.

[9] 2019 GT Plan Final Order at 9-10 (internal footnotes omitted).

Q. WHAT FINDING OR GUIDANCE DID THE COMMISSION PROVIDE FOR STAKEHOLDER ENGAGEMENT AND CUSTOMER EDUCATION IN 2019?

A. The Commission approved the stakeholder engagement and customer education costs to the extent they are necessary to support the various components approved in the 2019 GT Plan Final Order.[10]

Q. WHAT IS STAFF'S POSITION ON PHASE II STAKEHOLDER ENGAGEMENT AND CUSTOMER EDUCATION?

A. Staff supports approval of costs associated with stakeholder engagement and customer education contingent upon approval of any Phase II GT Plan component that the Commission approves. In general, Staff believes that these proposed programs, if properly implemented, would provide valuable opportunities to improve customer awareness of new programs and obtain customer inputs on such programs.

Customer Information Platform

Q. WHAT GUIDANCE DID THE COMMISSION PROVIDE FOR CIP?

A. In the 2019 GT Plan Final Order, the Commission found that the costs of the new customer information platform were reasonable and prudent and should be approved.[11]

Q. HAS THE COMMISSION PROVIDED GUIDANCE RELATIVE TO CIP IN ANY OTHER PROCEEDINGS?

A. Yes. In the Company's 2020 Integrated Resource Plan ("IRP") proceeding, Staff and Consumer Counsel raised concerns regarding the format and information provided on residential bills. As a result, in the 2020 IRP Final Order, the Commission stated:

[10] 2019 GT Plan Final Order at 10-11.
[11] 2019 GT Plan Final Order at 11.

> [W]e direct the Company to address the following in its next grid transformation plan filing: (1) the Company's plan and progress towards the redesign of the residential bill; (2) whether the current bill format continues to be sufficient under 20 VAC 5-312-90; and (3) alternative bill format proposals for the Commission's consideration. Given the uncertainty of the timing of the Company's next grid transformation plan filing, the Commission shall, should it see fit, address this issue in a future stand-alone proceeding, or triennial review (after 2021).[12]

Q. BASED ON THIS GUIDANCE, WHAT IS STAFF'S POSITION ON PHASE II CIP?

A. Staff supports approval of the proposed Phase II CIP as it represents a continuation of the previously approved Phase IB portion of the CIP's Core Project[13] which is projected to go live in the second quarter of 2023 and whose costs are supported by multiple vendor agreements.

Pilot Programs and Hosting Capacity Analysis

Q. WHAT COST CATEGORIES OF PHASE II WOULD FIT UNDER THE 2019 PILOT PROGRAMS AND HOSTING CAPACITY ANALYSIS CATEGORY?

A. In the 2019 GT Plan Final Order, the Commission found the Company's Locks Campus Microgrid, the Smart Charging Pilot, and the Hosting Capacity Analysis to each be reasonable and prudent.[14] The Company is not proposing additional pilot programs or improvements to the Hosting Capacity Analysis program in Phase II. As such, there are no programs proposed in Phase II that would fit under these two 2019 cost categories.

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[12] 2020 IRP Final Order at 16.

[13] The CIP Core Project includes replacement of the Company's Customer Information System (responsible for supporting metering, billing, credit, service orders, and revenue reporting), and customer-facing applications (web and mobile interfaces.

[14] 2019 GT Plan Final Order at 13-16.

Grid Infrastructure (Hardening)[15]

Q. WHAT COST CATEGORIES OF PHASE II WOULD FIT UNDER THE 2019 GRID HARDENING CATEGORY?

A. The Company's proposed Phase II cost categories for targeted corridor improvement and voltage island mitigation would fit under this 2019 category. For Phase II targeted corridor improvement, the Company has identified $16.3 million in O&M costs consisting of $11.8 million for ash tree remediation and $4.5 million for the herbicide program.[16] For voltage island mitigation, the Company has identified $11.4 million in capital costs.[17] The Company's 2019 GT Plan's Grid Hardening category also included mainfeeder hardening and proactive component upgrade components; however, neither of those specific components are included in the Company's Phase II filing.[18]

Q. WHAT FINDINGS OR GUIDANCE DID THE COMMISSION PROVIDE FOR TARGETED CORRIDOR IMPROVEMENT AND VOLTAGE ISLAND MITIGATION?

A. The Commission found that both the ash tree mortality and the herbicide programs were reasonable and prudent.[19] In addition, the Commission also found that the two voltage islands that the Company proposed to mitigate were reasonable and prudent at the level proposed for Phase IB.[20]

[15] In previous GT Plan filings and in the Commission's 2019 GT Plan Final Order, this category is referred to as "Grid Hardening." However, Phase II's "Grid Infrastructure" proposal includes elements that would have fit under the previously named Grid Hardening category. Phase II Grid Infrastructure is discussed later in this testimony.
[16] Wright Direct at 14.
[17] Wright Direct at 18.
[18] In its 2019 GT Plan Final Order, the Commission denied the Company's Proactive Component Upgrades program and found that the Company's Phase IB mainfeeder hardening was reasonable and prudent.
[19] 2019 GT Plan Final Order at 19.
[20] 2019 GT Plan Final Order at 20.

Q. BASED ON THIS GUIDANCE, WHAT IS STAFF'S POSITION ON PHASE II TARGETED CORRIDOR IMPROVEMENT AND VOLTAGE ISLAND MITIGATION?

A. Staff supports approval of costs associated with ash tree mortality and the herbicide programs as they are consistent with previously approved programs and the costs are based on existing contracts. Staff also supports approval of the Company's four voltage island mitigation projects as they are consistent with those projects approved in Phase IB. Additional discussion regarding voltage island mitigation is found later in my testimony.

Self-healing Grid and Related Investments

Q. WHAT COST CATEGORIES OF PHASE II WOULD FIT UNDER THE SELF-HEALING GRID AND RELATED INVESTMENTS?

A. In Phase II, the Company proposes a set of technologies referred to as Grid Technologies that would fit into this category. For Phase II, the Company is seeking approval of costs associated with the following Grid Technologies elements:[21]

- Intelligent Grid Devices;
- Fault Location, Isolation, Service Restoration Software ("FLISR");[22]
- Distributed Energy Resources Management System ("DERMS");
- Enterprise Asset Management System ("EAMS");
- Voltage Optimization Enablement; and
- Substation Technology Deployment.

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[21] The Company considers costs associated with the hosting capacity and Locks Campus Microgrid to be included in the grid technologies; however, these elements are not included in Phase II.
[22] In its 2019 GT Plan, the Company referred to this technology as "the self-healing grid."

In his testimony, Staff's consultant Volkmann provides analysis of these elements based on guidance provided by the Commission.

Physical Security

Q. WHAT WAS THE COMMISSION'S FINDING RELATIVE TO PHYSICAL SECURITY?

A. The Commission's 2018 GT Plan Final Order stated that the Commission "generally supports reasonable utility spending to support enhanced utility security."[23]

Q. BASED ON THIS FINDING, WHAT IS STAFF'S POSITION ON PHASE II PHYSICAL SECURITY?

A. While the Company acknowledges that costs per substation in Phase IA was higher than initially anticipated,[24] Staff supports approval of the proposed physical security in Phase II as it should, among other things, help to mitigate adverse events and improve reliability. Additional discussion on the Company's proposed Phase II Physical Security is provided later in my testimony.

V. ASSESSMENT OF SELECTED GT PLAN COMPONENTS AND COMPLIANCE WITH ENVIRONMENTAL JUSTICE PRINCIPLES

Q. WHICH GT PLAN COMPONENTS WILL YOU BE DISCUSSING?

A. I will be discussing the following programs in my testimony:

- AMI
- Grid Infrastructure
- Grid Technologies
- Physical Security

[23] 2018 GT Plan Final Order at 7.

[24] Bransky Direct at 9. The Company did not propose Physical Security as part of Phase IB.

In addition to the components listed above, I will also provide some testimony related to Environmental Justice.

AMI

Q. IN RESPONSE TO THE COMMISSION'S GUIDANCE IN THE 2019 GT PLAN FINAL ORDER YOU DISCUSSED EARLIER, WHAT TYPES OF SYSTEM-WIDE TIME-VARYING RATES DOES DOMINION IDENTIFY IN ITS PETITION?

A. The Company identified three time-varying rate programs in its Petition: i) Time-of-use ("TOU") Rates; ii) Peak-time rebate ("PTR") Programs; and iii) Real-time Pricing ("RTP") Rates. Rates, such as these, can incentivize participating customers to reduce usage during peak periods and enable the Company to avoid operating expenses such as fuel and future capacity costs.

Q. DOES THE COMPANY CURRENTLY HAVE TIME-VARYING RATE SCHEDULES AVAILABLE FOR CUSTOMERS?

A. Yes. The Company currently has three time-varying rate schedules available to residential customers. TOU Schedules 1S and 1T have been available for several decades; however, according to the Company, these plans do not have adequate "on-peak" hours to incentivize behavioral changes. More recently, in May 2020, the Commission approved the Company's application for an experimental time-of-use rate, designated TOU Rate Schedule 1G ("Schedule 1G").[25] Schedule 1G became available to customers in January 2021.

[25] *See Application of Virginia Electric and Power Company, For approval to establish an experimental residential rate, designated Time-Of-Use Rate Schedule 1G (Experimental),* Case No. PUR-2019-00214, Doc. Con. Cen. No. 200540136, Final Order Approving Experiment (May 20, 2020) ("Schedule 1G Final Order").

Q. WHAT GUIDANCE DID THE COMMISSION PROVIDE IN THE SCHEDULE 1G FINAL ORDER?

A. In the Schedule 1G Final Order, the Commission found:

> Dominion plans for this experiment to lay the groundwork for a systemwide rollout of TOU rates. In this regard, the Commission finds that implementing TOU Schedule 1G at this time will serve only as an initial step toward the potential development of a systemwide rate design for TOU rates. Specifically, having found the Company's proposal meets the minimum requirements of the statute, the Commission further finds – and emphasizes – that much more data and detail will be necessary to determine the type and structure of a TOU rate design that will serve the public interest on a significantly wider scale. Accordingly, as information regarding the actual implementation of this experiment becomes available, the Company shall file proposed modifications thereto designed to strengthen the robustness and efficacy of this experimental program.[26]

The Company's first annual report on the Schedule 1G experiment is required to be filed by December 31, 2021.

Q. IS THE COMPANY'S PLAN FOR TIME-VARYING RATES SYSTEM-WIDE?

A. Yes. However, the actual availability of a system-wide TOU rate would need to coincide with the deployments of both AMI and CIP. AMI meters are needed by the Company to capture the real-time interval energy usage and customer voltages, while the updated CIP is required to offer the TOU rates on a system-wide scale. The Company has identified the following timeline for implementing systemwide time-varying rates:

[26] Schedule 1G Final Order at 3.

Table 3: Timeline for Time-varying Rates[27]

Date	Action Item
January 2021	Launch Schedule 1G
December 2022	Include proposal for system-wide opt-in PTR program with DSM proceeding
April 2023	Launch CIP Core Project
January 2024	Launch system-wide opt-in PTR program
March 2024	Include proposal for system-wide TOU rate with triennial review filing
December 2024	Complete deployment of AMI
January 2025	Launch system-wide TOU rate

The Company anticipates that a proposal for approval of a system-wide TOU rate would be included with the Company's triennial review proceeding in March 2024 and, if approved, be available for customers in January 2025.

Q. DOES DOMINION PLAN TO MAKE A TIME-OF-USE RATE THE DEFAULT TARIFF FOR RESIDENTIAL CUSTOMERS WITH INSTALLED SMART METERS?

A. No, Dominion states that it does not believe it would be appropriate at this time to change the default tariff for residential customers to a TOU rate. In support of this "opt-in" approach, the Company notes that it would like to evaluate education channels and strategies of Schedule 1G during its current pilot. Furthermore, the Company states that its preference is to provide all residential customers an opportunity to understand the impacts of TOU rates on their bills. To achieve this goal, Dominion asserts that a full year of interval usage data collected from a customer's AMI meter would be required for a proper comparison of TOU versus non-TOU impacts on a customer's bill.

[27] *See* Company's GT Plan Document, Appendix D at 5.

Q. COULD A TOU TARIFF, SUCH AS SCHEDULE 1G, BECOME THE DEFAULT TARIFF FOR CUSTOMERS WITH AN AMI METER?

A. Yes, Dominion states that a default TOU tariff rate is a possibility; however, it would require future approval by the Commission. Furthermore, the Company believes that additional study would be required to ensure a change like this would be reasonable and equitable for all classes of customers and not lead to unintended consequences for vulnerable customers such as low-income, fixed-income, and those with medical conditions.

Q. HAS THE COMMISSION APPROVED COST RECOVERY FOR AMI METER DEPLOYMENT FOR ANY OTHER INVESTOR-OWNED REGULATED UTILITY?

A. Yes. In 2020, Appalachian Power Company ("APCo") filed an application for a triennial review of its rates, terms and conditions for the provision of generation, distribution and transmission services. The Commission found, among other things, that "[b]ased on the specific facts and circumstances in this record regarding Appalachian's decision to replace its old automated meter reading ("AMR)" fleet with AMI, the Commission finds that [APCo] has shown its decision to incur such costs was reasonable at the time the decision was made, such that these expenses should not be disallowed for determining Appalachian's earnings during the triennial review period."[28] Furthermore, the Commission stated that "[i]n short, we find that Appalachian has established it needed to

[28] *Application of Appalachian Power Company, For a 2020 triennial review of the rates, terms and Conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2020-00015, Doc. Con. Cen. No. 210330171, Order on Reconsideration at 23 (Mar. 26, 2021) (internal footnotes omitted).

replace its existing AMR meters, and that based on the uncertainty surrounding the continued manufacturing and support of AMR technology, [APCo] reasonably chose to replace them with AMI meters."[29]

Q. WHAT IS STAFF'S POSITION ON DOMINION'S REQUEST FOR APPROVAL OF THE AMI COMPONENT IN THIS PROCEEDING?

A. Should the Commission determine that the Company has sufficiently addressed the Commission's previous concerns regarding AMI deployment, Staff does not oppose approval of the AMI component.

Grid Infrastructure

Q. PLEASE PROVIDE AN OVERVIEW OF THE GRID INFRASTRUCTURE PROGRAMS PROPOSED UNDER PHASE II.

A. Under Phase II, the Company proposes to deploy the following grid infrastructure programs:

- Targeted Corridor Improvement
- Voltage Island Mitigation

Q. PLEASE DESCRIBE THE COMPANY'S VOLTAGE ISLAND MITIGATION PROGRAM.

A. The Company defines voltage islands as areas of its service territory where a single substation transformer serves a population of customers without support of available load transfer capability within the substation or through field tie switches to adjacent feeders.[30]

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[29] *Id.* at 24.
[30] GT Plan Document at 22.

Areas, such as these, are particularly susceptible to extended outages should the substation transformer fail. To mitigate this concern, the Company would typically install a second transformer at each location and reconfigure the existing feeders so that each serves a portion of the total customers and also provides adequate capacity to restore all customers in the event of the failure of any one transformer.[31] Two voltage islands were approved for mitigation as part of Phase IB and the Company has proposed four additional voltage islands as part of Phase II.

Q. HAS THE COMPANY MADE CHANGES TO THE VOLTAGE ISLAND MITIGATION PROGRAM AS A RESULT OF LESSONS LEARNED FROM PHASE I?

A. Yes. On June 14, 2021, the Commission granted the Company's request, among other things, to substitute the previously approved Chase City voltage island for the St. John's voltage island,[32] based on land acquisition and permitting issues cited by the Company. As a result, the Company states that it has performed preliminary assessments of the remaining 13 voltage islands to be addressed over the 10-year GT Plan period to evaluate if the existing substation footprints support the addition of transformers. For those where land acquisition would be necessary, the Company states that they have extended the project timelines.[33]

Q. DID THE COPMANY INVESTIGATE ANY ALTERNATE SOLUTIONS TO MITIGATE VOLTAGE ISLANDS?

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[31] *See* Company's Response to Staff Interrogatory Set 1, Question 12 in Attachment MAC-3.
[32] *See 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, Doc. Con. Cen. No. 210630055, Order Granting Motion (June 14, 2021).
[33] *See* Company's Response to Staff Interrogatory Set 7, Question 123.

A. Yes. The Company states that it considered alternatives such as extending new transmission or distribution sources into areas served by voltage islands but was unable to find cost effective alternatives. Additionally, the Company states that it considered and rejected non-wires alternatives such as battery storage due to the inability of this alternative to meet required load and duration requirements.

Q. HOW DO THE COMPANY'S PROPOSED PHASE II VOLTAGE ISLAND MITIGATION PROJECTS COMPARE TO THOSE FROM PHASE IB?

A. In terms of cost and scope of work, the four proposed Phase II voltage island mitigation projects appear to be consistent with the two projects approved as part of Phase IB. Three of the proposed projects will include the addition of a second substation transformer and the rearrangement of distribution feeders. The remaining project will include a new distribution class transformer and voltage conversion from 12.5 kV to 34.5 kV. Additionally, the Company does not anticipate any land acquisition will be required for the four proposed Phase II projects.

Grid Technologies

Q. DOES STAFF HAVE ANY CONCERNS WITH THE COMPANY'S GRID TECHNOLOGIES PROPOSAL?

A. Yes. As the Company notes, the two core objectives for grid transformation are: (i) facilitating the integration of DERs; and (ii) enhancing grid reliability and security.[34] To that end, the Company plans to utilize AMI and intelligent grid devices to gather system data. That data is then transmitted back over a secure telecommunications network. This

[34] GT Plan Document at 2.

would all be managed by a sophisticated DER management system ("DERMS"), and an enterprise asset management system ("EAMS"). In addition, the Company states:

> In Phase II, the primary focus leans more heavily into facilitating the integration of DERs, while continuing to address the reality that reliability and security are vital to the success of DERs. Industry developments in the past year alone will accelerate the proliferation of DERs, from the development targets for DERs set forth in the Virginia Clean Economy Act of 2020 ("VCEA"), to the market opportunities for DERs enabled by FERC Order 2222, to the myriad of commitments and incentives to speed the transition to electric vehicles. Stated simply, there is no doubt that significant volumes of DERs are coming to Virginia imminently. The distribution grid must be ready.[35]

Staff generally acknowledges this sentiment; however, Staff has serious concerns about the Company's ability to process the expected influx of DER interconnection requests it receives in a timely and efficient manner.

Q. CAN YOU ELABORATE ON THESE CONCERNS?

A. Yes. By way of background, on July 29, 2020, the Commission adopted revised Regulations Governing Interconnection of Small Electrical Generators and Storage, 20 VAC 5-314-10 *et seq.* ("Interconnection Regulations"), in Case No. PUR-2018-00107.[36] The revised Interconnection Regulations became effective on October 15, 2020. Among other changes, the updated regulations provided clarifying language, incorporated updated technical standards, and addressed several interconnection process concerns that had been relayed to Staff over the years by both electric utilities and their interconnection customers (private developers). The predominant concern expressed had been the inordinate length of time taken for queued DER projects to complete the interconnection

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[35] GT Plan Document at 2.

[36] *Commonwealth of Virginia, ex.rel. State Corporation Commission, Ex Parte: In the matter of revising the Commission's Regulations Governing Interconnection of Small Electrical Generators*, Case No. PUR-2018-00107, Doc. Con. Cen. No. 200740003, Order Adopting Regulations (July 29, 2020).

process. The revised Interconnection Regulations streamlined the interconnection process by more clearly defining the study process timeline and removing certain bottlenecks that previously allowed an interconnection customer to potentially hold a study queue position indefinitely, thereby preventing other queued projects from advancing along the interconnection study process.

Q. HAVE THE REVISED REGULATIONS IMPROVED THE SMALL GENERATOR INTERCONNECTION PROCESS?

A. Yes. Based on informal feedback received from both utilities and developers, the revised Interconnection Regulations appear to have improved the small generator interconnection process.

Q. HAVE ANY NEW ISSUES BEEN IDENTIFIED SINCE THOSE REGULATIONS WERE UPDATED?

A. Yes. As the Commonwealth continues to see a proliferation of renewable energy resources, there has been an increase in the volume of informal complaints received by Staff from developers seeking to interconnect DERs within the Company's service territory.

Q. CAN YOU SUMMARIZE THESE COMPLAINTS?

A. Yes. Two consistent themes have emerged from these complaints: 1) Developers are seeing an even greater length of time taken to complete their interconnection studies; and 2) the costs required to interconnect developers' facilities to the Company's distribution system are, according to the developers, higher than those imposed by other utilities across the country for similar interconnections.[37] For purposes of the instant proceeding, Staff believes the study time concern is of utmost importance, because timely processing of DER

[37] A related concern expressed by developers is a lack of transparency by the Company in providing information on how costs are obtained.

interconnection requests is imperative. If the interconnection study queue remains a significant bottleneck to DER integration within the Commonwealth, then many of the benefits proffered by the Company's deployment of Company's GT Plan components may either not be realized at all, or not fully achieved.

Q. DOES THE COMPANY'S TOTAL PROCESSING TIME FOR SMALL GENERATOR INTERCONNECTION REQUESTS ALIGN WITH THAT IDENTIFIED IN THE COMMISSION'S INTERCONNECTION REGULATIONS?

A. No. In response to Staff Interrogatory Question No. 129, Dominion stated that, on average, it takes approximately 300 business days to process an interconnection request starting from the receipt of the request until completion of the executable small generator interconnection agreement ("SGIA").[38] To begin a comparison with the Interconnection Regulations, it should first be noted that the Regulations identify timelines in terms of a maximum number of business days allowed for each *individual* step in the interconnection process. A cumulative assessment of these individual timelines shows that a developer submitting an interconnection request should receive an executable SGIA from the Company no more than 260 business days after the utility receives the initial interconnection request from the developer.[39] Notably, the 260 business days is a "worst-case" scenario that assumes that all three interconnection studies[40] are to be performed, and that both the utility and developer do not complete their required responsibilities until the *last allowable day* of each step. In practice, those responsibilities could conceivably be

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[38] *See* Company's Response to Staff Interrogatory Set 9, Question 129. This assumes there are no initial interdependency between the submitted project and other projects ahead of it in the queue.

[39] A diagram depicting how the 280 business days is derived is shown in Attachment MAC-1.

[40] The interconnection study process can include up to three studies: i) Feasibility Study; ii) System Impact Study; and iii) Facilities Study. The studies may also be combined, as explained later in my testimony.

completed well before the last day required, hence the belief that the 260-business day figure is a conservative (worst-case) limit.

Q. WHAT DO YOU BELIEVE TO BE A MORE REASONABLE BENCHMARK FOR THE EXPECTED TOTAL PROCESSING TIME FOR INTERCONNECTION REQUESTS?

A. I believe that a 195-business day process may be a more reasonable benchmark.

Q. AND HOW DID YOU ARRIVE AT THIS BENCHMARK?

A. This benchmark is based on the analysis shown in my Attachment MAC-1. The total process timeline for all three interconnection studies may be considered to consist primarily of: 1) actual technical study times, and 2) scheduling/communication times between the involved parties (utility, developer, etc.), and the individual maximum timeline associated with each step is shown in the Attachment. To arrive at my benchmark, Staff assumed the technical study time remains unchanged, but assumed that all of the scheduling and communication related tasks in the process could be completed, on average, within half of the maximum allotted time. For example, the process timeline allows the Company to take as many as 10 business days to provide a developer with each of the three study agreements. However, standard agreement templates are provided in the Interconnection Regulations, which in Staff's view should therefore allow the Company to provide these agreements with minimum editing effort and with shorter associated timelines.

Q. DO YOU HAVE FURTHER COMMENTS RELATIVE TO DOMINION'S PROCESS TIMES FOR DER INTERCONNECTION REQUESTS?

A. Yes. A more granular inspection of the Company's processing time for each of the three interconnection studies provides a better gauge of the Company's ability to keep pace with interconnection requests. First, Staff notes the Company's preference for performing "Combined" Studies[41] over individual studies for interconnection requests. The intended benefit of a Combined Study is to provide a more streamlined and faster interconnection process, by eliminating many developer-utility interactions typically associated with individual studies.[42] However, feedback received from DER developers is that Combined Studies, right from the onset, are often estimated by the Company to require the same length of time as individual studies, defeating that time saving purpose. Such equal timeline estimates are indeed often borne out by the actual time taken to complete the study processes, according to developers. In his testimony, Staff consultant Volkmann recommends the Company publish a semi-annual interconnection report. Staff agrees with this recommendation.

Q. CAN YOU REITERATE WHY YOU CONSIDER THE COMPANY'S LONG INTERCONNECTION STUDY PROCESS TO BE A PROBLEM RELATIVE TO THE GOALS OF THE COMPANY'S GT PLAN?

A. Yes. The Company states in its GT Plan filings that it has already seen significant growth in DERs within Virginia and that it expects DER growth to continue exponentially in the coming years. This assertion has formed a basis for requiring many of the proposed elements of the GT Plan. Staff generally agrees that grid technologies, such as those proposed in the instant proceeding, may be critical to meeting goals established by the passage of the VCEA. However, Staff has significant concerns relative to the Company's

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[41] Combined Studies can be performed by based on mutual, written agreement of both parties, and allow the Company to combine the feasibility, system impact, and facilities studies (as required) into a single report.

[42] For example, once a Combined Study is returned, subsequent agreements for System Impact and Facilities study are avoided resulting in the removal of approximately 25 business days and 40 business days, respectively. See Attachment MAC-1.

ability to efficiently process this great influx of DER interconnection requests if the Company's interconnection request study process continues to be the significant bottleneck to DER deployment as appears to be the case, based on numerous complaints received from renewable energy developers. This bottleneck could well make it difficult for Dominion to meet the VCEA goals or to maximize the benefits of the GT Plan's Grid Technologies program. As such, Staff believes the Commission should direct the Company to take steps to significantly improve its small generator interconnection process to remove this bottleneck. Staff's consultant Volkmann's testimony describes additional concerns and offers recommendations related to the time it takes for the Company to process net energy metering ("NEM") requests.

Q. WHAT RECOMMENDATIONS DOES STAFF HAVE TO IMPROVE DOMINION'S SMALL GENERATOR INTERCONNECTION PROCESS?

A. Should the Commission approve AMI, DERMS, and Intelligent Grid Devices, Dominion should be required to:

- Provide a public interconnection queue hosted on the Company's website, and updated monthly;
- Upgrade the Company's Hosting Capacity Analysis to include additional feeder information such as feeder number, substation name serving the feeder, voltage, existing and queued generation; and
- Provide a Unit Cost Guide for DER developers so that they may better understand potential interconnection cost impacts.

Q. HOW WILL STAFF'S RECOMMENDATIONS IMPROVE THE INTERCONNECTION PROCESS?

A. A publicly available interconnection queue provides greater transparency for developers wishing to interconnect in the Company's service territory. This additional insight provided to developers will improve developers' ability to determine the viability of proposed projects, thus saving the time and expense of speculative interconnection requests. For example, a developer utilizing a public interconnection queue and hosting capacity map could more easily identify suitable locations which not only have available capacity, but also avoid the potential long delays associated with interdependency with other projects.[43] Furthermore, a project deemed viable based on this information may then be able to accelerate or altogether eliminate the feasibility study portion of the interconnection process. The expected reduction in speculative interconnection request filings would also benefit the Company, as Dominion's resources could then be better utilized in processing viable project requests.

Q. DO ANY OTHER INVESTOR-OWNED REGULATED UTILITIES IN VIRGINIA MAINTAIN A PUBLICLY AVAILABLE INTERCONNECTION QUEUE?

A. Yes. APCo has recently begun publishing their Virginia interconnection queue on their website.[44] APCo's queue, which is currently updated quarterly, provides the following information:

- APCo Dist. Queue #
- SGF[45] Physical Address
- Fuel Type
- Capacity (MW)

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[43] An interdependent project is a project whose upgrades to the utility system or attachment facilities are impacted by another earlier-queued generating facility.
[44] https://www.appalachianpower.com/business/builders/generating-equipment
[45] Small Generation Facility

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- Substation/Transformer
- Circuit
- Date of Submission of Final Completed Interconnect Request Form
- Interdependency Status (Project A or B)
- Project Status
- Date of Final Executed SGIA

A copy of APCo's public generation queue as of 7/30/2021 can be found in Attachment MAC-2.

Q. CAN YOU DESCRIBE THE STATUS OF THE HOSTING CAPACITY ANALYSIS PREVIOUSLY APPROVED BY THE COMMISSION?

A. Yes. In Phase IB, the Company proposed and received approval[46] for a Hosting Capacity Analysis, which Dominion has since deployed.[47] This component consists of a publicly available web-based tool that allows developers and localities to evaluate optimal locations for DER through a color-coded map depicting the available capacity on the distribution system.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THAT HOSTING CAPACITY ANALYSIS TOOL?

A. Yes. The Hosting Capacity Analysis currently displays active (already deployed) generation capacity only.[48] Staff recommends that the Company incorporate queued interconnection projects and additional information such as feeder numbers, substation

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[46] 2019 GT Plan Final Order at 16.

[47] The Company's Hosting Capacity Tool can be accessed at https://www.dominionenergy.com/projects-and-facilities/electric-projects/energy-grid-transformation/hosting-capacity-tool

[48] The Company plans to add hosting capacity information for net metering installations by the end of 2021. See Company's Response to Staff Interrogatory Set 7, Question 125.

names and voltage into the Hosting Capacity Analysis, to provide developers a clearer picture of viable locations to propose their projects. This would provide the same benefits previously described, i.e. a reduction in speculative interconnection request filings and the freeing up of Company resources. Staff's consultant Volkmann provides additional recommended enhancements to the Company's Hosting Capacity Analysis in his testimony.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS TO IMPROVE THE INTERCONNECTION PROCESS?

A. Yes. Staff believes that the Company should develop and maintain a "Unit Cost Guide" for DER developers so that they may better assess potential interconnection costs. While guides, such as these, are not intended to provide binding cost estimates, they provide improved transparency for developers and serve as another tool to assess the viability of a project. Unit Cost Guides have been in place in California since 2016 and the utilities are required to update costs annually.[49]

Physical Security

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PHYSICAL SECURITY PROGRAM.

A. The Company's Physical Security Program proposes to harden certain distribution substations with improved security, allowing them to detect, mitigate, and prevent potential threats, and reduce the likelihood of successful physical attacks. According to the

[49] *See* California Public Utility Commission Decision D.16-06-052 dated July 1, 2016. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K376/164376491.pdf

Company, this program, which is anticipated to impact 46 of the Company's substations over the 10-year GT Plan period, will help to minimize the disruption of services to customers, reduce risk to the general public, and continue reliable and safe operations and service.[50] As part of the Company's Phase IA GT Plan, the Company has completed work on one critical substation, with three additional substations expected to be completed by the end of 2021. Under Phase II, the Company proposes to continue its program to harden an additional 12 critical distribution substations with improved security such as strengthening the substation perimeter, securing access points to and within the substations, and improving capabilities to monitor and detect threats at the substations.[51]

Q. HOW DOES THE COMPANY'S PROPOSED PHASE II PHYSICAL SECURITY PROJECTS COMPARE TO THOSE FROM PHASE IA?

A. According to the Company, the physical security solutions and technologies proposed as part of Phase II are the same as those deployed under Phase IA. However, the Company has indicated that the costs per substation under Phase IA were higher than initially anticipated due to several reasons, such as higher material costs, improved security fencing standards, the need to potentially rearrange substation equipment and feeders to accommodate taller fences, and groundwork and grading to allow for anti-digging benefits to be realized.[52]

[50] *See* Company's Response to Staff Interrogatory Set 5, Question 100 and Bransky Direct at 10.
[51] Bransky Direct at 7.
[52] *See* Company's Response to Staff Interrogatory Set 5, Question 101.

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Environmental Justice

Q. DID THE COMPANY EVALUATE THE GT PLAN'S IMPACT RELATIVE TO ENVIRONMENTAL JUSTICE?

A. Yes. In its Petition, the Company affirmed its commitment to meeting the Commonwealth's environmental justice expectations by, in part, performing an environmental justice evaluation of the GT Plan. By way of background, in 2018, the Company adopted an environmental justice policy[53] which, among other things, expresses the Company's commitment to allowing all communities an opportunity to participate in the planning and development process. To that end, the Company intends to provide communities a voice in decisions about siting and operation of energy infrastructure and to provide communities ready access to accurate information and a meaningful voice in the project development process.[54] The Company engaged in outreach with stakeholders and stakeholders' representative groups prior to filing its 2019 GT Plan. The stakeholder group re-convened prior to the filing of the Petition and held three sessions to update the stakeholders on the GT Plan and to provide stakeholders an opportunity for feedback.[55]

Q. PLEASE DESCRIBE THE COMPANY'S ENVIRONMENTAL JUSTICE EVALUATION.

A. To understand the environmental justice impacts, the Company evaluated each GT Plan component separately. As noted by the Company, the CIP, FLISR, DERMS, EAMS, cyber security, and customer education components proposed for Phase II do not have a physical

[53] https://sustainability.dominionenergy.com/engaging-communities/environmental-justice/
[54] GT Plan Document at 17.
[55] GT Plan Document at 16.

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component that would cause any environmental consequence.[56] The remaining components (AMI, Targeted Corridor Improvement, Voltage Island Mitigation, Intelligent Grid Devices, Voltage Optimization Enablement, Substation Technology, Physical Security, and Telecommunications) will require work in communities. For these eight components requiring work in communities, some are meant to be adopted broadly across the Company's service territory (i.e. AMI and voltage optimization) while others are focused on mitigating reliability, resiliency, and security risks in select areas (i.e. voltage island mitigation, substation technology deployment, and physical security).

Q. DO YOU HAVE ANY ENVIRONMENTAL JUSTICE CONCLUSIONS OR RECOMMENDATIONS RELATIVE TO PHASE II?

A. Yes. Based on the evidence provided, the Company's proposed Phase II appears to be consistent with the Commonwealth's principles of environmental justice. The Company stated that it has engaged a third-party consultant to evaluate the eight aforementioned Phase II grid transformation projects which require physical work in communities. Staff supports this effort and requests the Commission require the Company to submit the results of this evaluation to Staff upon completion.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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[56] GT Plan Document at 18.

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Attachments

Attachment MAC- 1: Interconnection Process Timeline

bd = Business days
(C) = Communication or Scheduling Task (130 bd)
(S) = Study Task (120 bd)

Phase	Milestone	Time		Type	Requirement
	Interconnection Request				
		10	bd		A scoping meeting shall be held no later than 10 bd after interconnection request form deemed complete.
	Scoping Meeting				
		10	bd	(C)	Utility shall provide the IC a feasibility study agreement no more than 10 bd from scoping meeting
Feasibility Study	Feasibility Agreement				
Feasibility Study		15	bd	(C)	IC must return executed FS Agreement to utility within 15 bd
Feasibility Study	Executed Feasibility Agreement				
Feasibility Study		30	bd	(S)	Feasibility study shall be prepared and transmitted to the IC within 30 bd of receipt of the FS Agreement
Feasibility Study	Feasibility Study Returned				
		10	bd	(C)	Utility shall provide the IC a system impact study agreement no more than 10 bd after FS Study returned
System Impact Study	System Impact Agreement				
System Impact Study		15	bd	(C)	IC must return executed SI Agreement to utility within 15 bd of receipt
System Impact Study	Return System Impact Agreement				
System Impact Study		45	bd	(S)	System Impact study shall be prepared and transmitted to IC 45 bd after receipt of SI Agreement
System Impact Study		20	bd*	(S)	20 bd added if a neighboring utility is affected.
System Impact Study	Return System Impact Study				
		10	bd	(C)	Utility shall provide the IC a Facility Study Agreement no more than 10 bd after System Impact Agreement is Complete
Facility Study	Facility Study Agreement				
Facility Study		30	bd	(C)	IC must return executed Facility Study Agreement to utility within 30 bd of receipt
Facility Study	Return Facility Study Agreement				
Facility Study		45	bd	(S)	Utility shall transmit the facilities study report within 45 business days after receipt of the completed Facilities Study Agreement.
Facility Study	Return Facility Study				
		15	bd	(C)	the IC shall request a construction planning meeting within 15 bd of receipt of Facility Study Report
		15	bd	(C)	The construction planning meeting shall be scheduled within 15 business days of the request from the IC.
	Construction Planning Meeting				
		10	bd	(C)	Utility shall provide the IC an executable SGIA within 10 bd of the Construction Planning Meeting.
	Executable SGIA provided to IC				

Executable SGIA within: 260 bd* (does not include the 20 bd for affected system as this is not typically required)
or approximately: 364 calendar days

Attachment MAC- 2: APCo Interconnection Queue

As of 07/30/2021

Queue Position	Site Location/Address	Fuel Type	Capacity (MW)	Substation/Transformer	Circuit	Date of Submission of Final Completed Interconnection Request Form	Interdependency Status (Project A or B)	Project Status	Date of Final Executed ISA
Pre-Queue	Flanagan Dam Rd, Haysi, VA	Water	1.2 MW	Haysi/ 69-12.47 kV, 20 MVA	Bartlick 12.47 kV	7/7/2014		Withdrawn	
APCo_VA_00100	2395 Salem Rd, Schuyler, VA	Water	.822 MW	Schuyler/46-12.47 kV, 2 MVA	Schuyler 12.47 kV	9/3/2014	A	Active	6/11/2015
APCo_VA_00101	Depot Rd, Rustburg, VA	Solar	10 MW	Rustburg/138-12.47 kV, 20 MVA	Willow Lake 12.47 kV	8/13/2015	A	Active	9/16/2020
APCo_VA_00102	6 Mile Post Rd, Rocky Mount, VA	Solar	10 MW	Franklin/138-12.47 kV, 22.4 MVA	Grassy Hill 12.47 kV	12/3/2015, 11:05 AM		Withdrawn	
APCo_VA_00103	3311 Mud Pike, Christiansburg, VA	Solar	10 MW	Edgemont/138-12.47 kV, 22.4 MVA	Mudpike 12.47 kV	12/3/2015, 2:46 PM		Withdrawn	
APCo_VA_00104	2684 Mud Pike, Christiansburg, VA	Solar	10 MW	Edgemont/138-12.47 kV, 22.4 MVA	Plum Creek 12.47 kV	12/4/2015, 11:59 AM		Withdrawn	
APCo_VA_00105a	2800 Lamb Cir, Christiansburg, VA	Solar	1 MW	Edgemont/138-12.47 kV, 22.4 MVA	Mudpike 12.47 kV	5/17/2016		In Service	12/5/2016
APCo_VA_00105b	6 Mile Post Rd, Rocky Mount, VA	Solar	10 MW	Franklin/138-12.47 kV, 22.4 MVA	Grassy Hill 12.47 kV	2/6/2017, 11:57 AM		Withdrawn	
APCo_VA_00106	2684 Mud Pike Rd, Christiansburg, VA	Solar	10 MW	Edgemont/138-12.47 kV, 22.4 MVA	Mudpike 12.47 kV	2/8/2017, 1:00 PM		Withdrawn	
APCo_VA_00107	Depot Rd, Rustburg, VA	Solar	5 MW	Rustburg/138-12.47 kV, 20 MVA	Rustburg 12.47 kV	2/22/2017, 10:52 AM	A	Active	9/16/2020
APCo_VA_00108	Monte Vista Dr, Pulaski, VA	Solar	18.4 MW	Peak Creek/138-34.5 kV, 30 MVA or	Not determined	2/24/2017, 9:51 AM		Withdrawn	
APCo_VA_00109	684 Gap of Ridge Rd, Rural Retreat, VA	Solar	20 MW	Rural Retreat/138-34.5 kV, 25 MVA	Rural Retreat 34.5 kV	2/24/2017, 9:52 AM		Withdrawn	
APCo_VA_00110	140 Foggy Ridge Rd, Rocky Mount, VA	Solar	10 MW	Blaine/138-34.5 kV, 30 MVA	Wirtz 34.5 kV	2/24/2017, 12:18 PM		Withdrawn	
APCo_VA_00111	Kents Ln, Wytheville, VA	Solar	15 MW	Progress Park/138-34.5 kV, 30MVA	Progress Park or Mabetown 34.5 kV	2/24/2017, 12:18 PM		Withdrawn	
APCo_VA_00112	4834 Old Franklin Tpk, Glade Hill, VA	Solar	10 MW	Redwood /138-12.47 kV, 20 MVA	Truevine 12.47 kV	2/24/2017, 12:20 PM		Withdrawn	
APCo_VA_00113	580 Glen Vale Rd, Rocky Mount, VA	Solar	10 MW	Blaine/138-34.5 kV, 30 MVA	Burnt Chimney 34.5 kV	2/24/2017, 12:20 PM		Withdrawn	
APCo_VA_00114	678 Brookneal Hwy, Rustburg, VA	Solar	5 MW	Rustburg/138-12.47 kV, 20 MVA	Rustburg 12.47 kV	2/24/2017, 12:22 PM		Withdrawn	
APCo_VA_00115	1146 Campbell Hwy, Rustburg, VA	Solar	10 MW	Rustburg/138-12.47 kV, 20 MVA	Rustburg 12.47 kV	2/24/2017, 12:22 PM		Withdrawn	
APCo_VA_00116	Gose Mill Rd, Tazewell, VA	Solar	5 MW	Buckhorn/138-34.5 kV, 30MVA	Bluefield Rd. 34.5 kV	2/24/2017, 2:17 PM		Withdrawn	
APCo_VA_00117	Narrows, VA	Solar	5 MW	Not determined	Not determined	2/24/2017, 2:17 PM		Withdrawn	
APCo_VA_00118	Ringgold Rd, Ringgold, VA	Solar	10 MW	Not in APCo service territory	Not in APCo service territory	2/24/20017, 3:28 PM		Withdrawn	
APCo_VA_00119	Cline & Citizens Rd, Rural Retreat, VA	Solar	5 MW	Rural Retreat /138-34.5 kV/25 MVA	Groseclose 34.5 kV	2/24/2017, 3:49 PM		Withdrawn	
APCo_VA_00120	630 Main St., Rural Retreat, VA	Solar	5 MW	Rural Retreat/138-34.5 kV, 25 MVA	Rural Retreat 34.5 kV	2/24/2017, 4 PM		Withdrawn	
APCo_VA_00121	1178 Lovers Ln, Wytheville, VA	Solar	10 MW	Wythe/138-34.5 kV, 25 or 35 MVA	Not determined	2/24/2017, 4 PM		Withdrawn	
APCo_VA_00122	340 Citizen Rd, Rural Retreat, VA	Solar	6 MW	Rural Retreat / 138-34.5 kV, 25 MVA	Rural Retreat 34.5 kV	2/24/2017, 4 PM		Withdrawn	
APCo_VA_00123	Mud Pike Rd, Christiansburg, VA	Solar	20 MW	Edgemont/138-12.47 kV, 22.4 MVA	Not determined	2/24/2017, 6:11 PM		Withdrawn	
APCo_VA_00124	1970 Roanoke Blvd, Salem, VA	Nat. Gas	1.43 MW	V.A. Hospital/34.5-4 kV, 10 MVA	34.5 kV Sub transmission loop	4/17/2017	A	Active	
APCo_VA_00125	Ross Ridge & Mountain Valley Rds, Henry	Solar	20 MW	Stockton/ 138-34.5 kV, 30 MVA	Sandy River 34.5 kV	11/16/2016	A	Active	9/23/2020
APCo_VA_00126	2128 Lynbrook Rd, Lynchburg, VA	Solar	15 MW	Lynbrook/138-12 kV, 20 MVA	Will require 2 POIs, undetermined	Request from PJM to study		Withdrawn	
APCo_VA_00127	1945 Warden Spring Rd, Pulaski, VA	Solar	20 MW	Peak Creek/138-34.5 kV, 30 MVA	Draper 34.5 kV	4/2/2018		Withdrawn	
APCo_VA_00128	1945 Warden Spring Rd, Pulaski, VA	Solar	5 MW	Peak Creek/138-12.47 kV, 20 MVA	Memorial Dr 12 kV	4/2/2018		Withdrawn	
APCo_VA_00129	SR 732 & Richmond Hwy, Amherst, VA	Solar	4.875 MW	Amherst/69-12.47 kV, 25MVA	Rutledge 12.47 kV	12/19/2018, 10:30 AM	A	Active	
APCo_VA_00130	1020 Fisher Farm Rd, Martinsville, VA	Solar	11 MW	Sheffield/138-34.5 kV, 30 MVA	Sheffield 34.5 kV	12/27/2018, 10:30 AM		Withdrawn	
APCo_VA_00131	Nye Rd, Wytheville, VA	Solar	20MW	Wythe/138-34.5 kV, 35 MVA	Nye Rd 34.5 kV	4/17/2019	A	Active	9/24/2020
APCo_VA_00132	Corporate Cir, Salem, VA	Nat Gas	2MW	TBD	TBD	9/30/2019	A	Active	
APCo_VA_00133	1541-1411 Co Rd 606 Bassett, VA 24055	Solar	5MW	Fieldale/34-12 kV, 10.9 MVA	Firestone 12 kV	10/25/2019 13:42	A	Active	
APCo_VA_00134	2-398 Beaver Hills Club Rd, Collinsville, VA	Solar	14MW	Martinsville/138-34.5 kV, 30 MVA	Fieldboro 34.5 kV	10/25/2019 1:43:00PM		Withdrawn	
APCo_VA_00135	Wheatland Rd, Fincastle, VA	Solar	10 MW	Wheatland/69-12.47 kV, 20 MVA	Springwood 12.47 kV	1/30/2020 10:41		Withdrawn	
APCo_VA_00136	Flannagan Dam Rd, Haysi, VA	Hydro	1.44 MW	Haysi/ 69-12.47 kV, 20 MVA	Bartlick 12.47 kV	5/4/2020 11:45		Withdrawn	
APCo_VA_00137	310-388 Ebony Dr, Martinsville, VA	Solar	3 MW	Sheffield/138-34.5 kV, 30 MVA	Cloverleaf 34.5 kV	5/7/2020 10:30AM	A	Active	
APCo_VA_00138	543-537 E Riverside Dr, N Tazewell, VA	Solar	12 MW	Buckhorn/138-34.5 kV, 30MVA	East Tazewell 34.5 kV	7/8/2020 9:44AM	A	Active	
APCo_VA_00139	310-398 Ebony Dr, Martinsville, VA	Solar	5 MW	Sheffield/138-34.5 kV, 30 MVA	Cloverleaf 34.5 kV	9/25/2020 16:08	A	Active	
APCo_VA_00140	E Lee Hwy, Wytheville, VA	Solar	13 MW	Wythe /138-34.5 kV, 25 MVA	Fort Chiswell 34.5 kV	10/15/2020 11:48	A	Active	
APCo_VA_00141	14186 Booker T Washington Hwy, Moneta, VA	Solar	20 MW	Westlake / 138-34.5 kV, 30 MVA	Westlake 34.5 kV	11/6/2020 17:53		Active	
APCo_VA_00142	1901 Graves Mill Rd, Lynchburg, VA	Diesel	0.5 MW	Mcconville 138-12.47 kV, 25 MVA	Rosedale 12.47 kV	12/21/20 3:41PM	A	Active	
APCo_VA_00143	1901 Graves Mill Rd, Lynchburg, VA	Diesel	3 MW	Mcconville 138-12.47 kV, 25 MVA	Rosedale 12.47 kV	12/21/20 3:41PM	A	Active	
APCo_VA_00144	1778 Virgil Goode Hwy, Oak Level, VA	Solar	5 MW	Oak Level 138-12.47 kV, 20 MVA	Fork Mountain 12.47 kV	01/25/2021 10:30AM	B	Active	
APCo_VA_00145	11918 Henry Rd, Henry, VA	Solar	5 MW	Oak Level 138-12.47 kV, 20 MVA	Fork Mountain 12.47 kV	01/25/2021 10:30AM	A	Active	
APCo_VA_00146	4325 Thomas Jefferson Rd, Forest, VA	Solar	18.9 MW	New London 138-34.5 kV, 30 MVA	New London 34.5 kV	1/28/2021 8:04PM	A	Active	
APCo_VA_00147	Hebron Rd, Galax, VA	Solar	20 MW	Cliffview 69-34.5 kV, 20 MVA	North 34.5 kV	2/18/2021 3:50PM	A	Active	
APCo_VA_00148	Joseph Martin Hwy, Martinsville, VA	Solar	20 MW	Sheffield 138-34.5 kV, 30 MVA	Sheffield Terrace 34.5 kV	2/18/2021 5:08PM	B	Active	
APCo_VA_00149	Burnt Chimney Rd, Wirtz, VA	Solar	6.7 MW	Westlake 138-34.5 kV, 30 MVA	Dudley 34.5 kV	2/18/2021 5:10PM		Active	
APCo_VA_00150	Marborne Manor Rd, Ridgeway, VA	Solar	18.8 MW	Ridgeway 138-34.5 kV, 25 MVA	Lithia Spring 34.5 kV	2/18/2021 5:11PM	A	Active	
APCo_VA_00151	Fisher Farm Rd, Martinsville, VA	Solar	7.25 MW	Sheffield 138-34.5 kV, 30 MVA	Fisher Farm 34.5 kV	2/18/2021 5:12PM	C	Active	
APCo_VA_00152	Government Plant Rd	Battery	10 MW	Saltville 138-12kV, 10.5 MVA	US Gypsum	2/23/2021 10:00	A	Withdrawn	

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APCo_VA_00153	2904 Caroll Avenue, Lynchburg, VA	Battery	10 MW	Perkins Park 69-12.47 kV, 20 MVA	Mosby Avenue 12.47 kV	2/23/2021 4:05PM	A	Active	
APCo_VA_00154	100 Old Trent's Ferry Rd & 3820 Harbor St.	Battery	10 MW	Reusens 69-12.47 kV, 20 MVA	Trents Ferry 12.47 kV	2/23/2021 4:05PM	A	Active	
APCo_VA_00155	Gratton Rd, Tazewell, VA 24651	Solar	15.5 MW	Buckhorn 138-34.5 kV, 30MVA	Gratton 34.5 kV	3/16/2021 9:57AM	A	Active	
APCo_VA_00156	Orby Cantrell Hwy, Pound, VA 24279	Solar	10.0 MW	Pound 69-34.5 kV, 25 MVA	Indian Creek 34.5 kV	4/18/2021 7:02.00AM	A	Active	
APCo_VA_00157	Bold Camp Rd, Pound, VA 24279	Solar	7.0 MW	Lick Fork 69-34.5 kV, 10.5 MVA	Birchfield 34.5 kV	4/18/2021 7:02AM	A	Active	
APCo_VA_00158	Bold Camp Rd, Pound, VA 24279	Solar	10.0 MW	Clintwood 69-12.47 kV, 20 MVA	Coeburn Road 12.47 kV	4/16/2021 7:03AM	A	Active	
APCo_VA_00159	Bold Camp Rd, Pound, VA 24279	Solar	4 MW	Clintwood 69-12.47 kV, 20 MVA	Coeburn Road 12.47 kV	4/16/2021 7:03AM	B	Active	
APCo_VA_00160	Richmond Hwy, Amherst, VA 24521	Solar	4.5 MW	Amherst 69-12.47 kV, 25MVA	Rutledge 12.47 kV	4/26/2021 12:04PM	A	Active	
APCo_VA_00161	White Rd, Goode, VA 24556	Solar	3.5 MW	Ivy Hill 138-12.47 kV, 20 MVA	Perrowville 12.47 kV	4/27/2021 7:52AM	A	Active	
APCo_VA_00162	9880 Greensboro Rd, Ridgeway, VA 24148	Solar	5 MW	Ridgeway 138-34.5 kV, 25 MVA	Mason Heights 12.47 kV	4/27/2021 8:23AM	A	Active	
APCo_VA_00163	77 Thomas Rd, Collinsville, VA 24078	Solar	5 MW	Collinsville 138-12.47 kV, 22.4 MVA	Kings Mountain 12.47 kV	4/27/2102 8:40PM	A	Active	
APCo_VA_00164	Digby Green Rd, Boones Mill, VA	Solar	4.85 MW	Blaine 138-34.5 kV, 30 MVA	Wirtz 34.5 kV	5/4/2021 11:22AM	A	Active	
APCo_VA_00165	543-537 E Riverside Dr, N Tazewell, VA	Solar	5 MW	Buckhorn 138-34.5 kV, 30MVA	East Tazewell 34.5 kV	6/15/2021 9:58AM	C	Active	
APCo_VA_00166	Burnt Chimney Rd, Wirtz, VA	Solar	20.0 MW	Westlake 138-34.5 kV, 30 MVA	Dudley 34.5 kV	6/18/2021 10:00AM	A	Active	
APCo_VA_00167	15550 Old Franklin Turnpike, Penhook, VA	Solar	18.8 MW	Penhook 138 - 34.5 kV, 30 MVA	Penhook 34.5 kV	6/21/21 12:08PM	A	Active	
APCo_VA_00168	15550 Old Franklin Turnpike, Penhook, VA	Solar	12.6 MW	Penhook 138 - 34.5 kV, 30 MVA	Waters Edge 34.5 kV	6/21/21 12:03PM	B	Active	
APCo_VA_00169	2904 Caroll Avenue, Lynchburg, VA	Battery	10.0 MW	Perkins Park 69-12.47 kV, 20 MVA	Mosby Avenue 12.47 kV	6/21/21 12:13PM	B	Active	
APCo_VA_00170	100 Old Trent's Ferry Rd & 3920 Harbor St.	Battery	10.0 MW	Reusens 69-12.47 kV, 20 MVA	Trents Ferry 12.47 kV	6/21/21 12:13PM	B	Active	
APCo_VA_00171	Flint Hill Rd, Cana VA, 24317	Solar	10 MW	Willis Gap 138-34.5 kV, 20 MVA	Cana 34.5 kV	7/12/21 4:52PM	A	Active	
APCo_VA_00172	Gilford Rd, Moneta, VA 24121	Solar	9 MW	Westlake 138-34.5 kV, 30 MVA	Bluewater 34.5 kV	7/13/21 9:21AM	A	Active	
APCo_VA_00173	Village Highway, Concord, VA 24538	Solar	4.9 MW	Sherwill 69-12.47 kV, 20 MVA	Village Highway 12.47 kV	7/14/21 1:107PM	A	Active	
APCo_VA_00174	271 Co. Rd 747, Fieldale, VA 24089	Solar	5 MW	Fieldale 138-34.5 kV, 33.3 MVA	Carver 34.5 kV	7/9/21 3:21PM	A	Active	
APCo_VA_00175	Roanoke Rd, Elliston, VA 24087	Solar	8 MW	Kumis 138-12.47 kV, 22.4 MVA	Elliston 12.47 kV	7/9/21 4:16PM	A	Active	
APCo_VA_00176	Commerce Dr, Stuart, VA 24171	Solar	12 MW	Stuart 69-34.5 kV, 30 MVA	Critz 34.5 kV	7/21/21 2:12PM	A	Active	
APCo_VA_00177	Commerce Dr, Stuart, VA 24171	Solar	20 MW	Stuart 69-34.5 kV, 30 MVA	Critz 34.5 kV	7/21/21 2:23PM	B	Active	

Withdrawn
Active
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Attachment MAC- 3: Company's Responses to Staff's Interrogatory Requests

Staff Interrogatories

Set 1 – Question 12

Set 5 – Question 100

Set 5 – Question 101

Set 7 – Question 123

Set 7 – Question 125

Set 9 – Question 129

Virginia Electric and Power Company
Case No. PUR-2021-00127
Virginia State Corporation Commission Staff
First Set

The following response to Question No. 12 of the First Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff and received on July 20, 2021 has been prepared under my supervision.

Richard C. Siepka
Manager, Electric Distribution Grid Planning
Dominion Energy Virginia

Question No. 12

Refer to the direct testimony of Robert Wright, p. 16, lines 10-11. Please explain how voltage island mitigation improves day-to-day service reliability.

Response:

Voltage island mitigation typically involves installing a second transformer at the substation and rearranging the distribution feeders to serve some portion of customers from the new transformer. This sort of rearrangement reduces the number of customers affected by feeder-level outages that occur as part of day-to-day activities and provides new capabilities to restore customers using feeder ties.

Virginia Electric and Power Company
Case No. PUR-2021-00127
Virginia State Corporation Commission Staff
Fifth Set

The following response to Question No. 100 of the First Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff and received on August 16, 2021 has been prepared under my supervision.

Jonathan Bransky
Director Threat Intelligence
Dominion Energy Services

Question No. 100

Please reference Company witness Bransky's direct testimony on page 7, which states that the Company proposes to improve security at 12 distribution substations during Phase II. How many substations does the Company anticipate will require physical security improvements over the 10-year GT Plan period?

Response:

The Company anticipates improving security at 46 substations over the 10-year GT Plan period.

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Virginia Electric and Power Company
Case No. PUR-2021-00127
Virginia State Corporation Commission Staff
Fifth Set

The following response to Question No. 101 of the First Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff and received on August 16, 2021 has been prepared under my supervision.

Jonathan Bransky
Director Threat Intelligence
Dominion Energy Services

Question No. 101

Please reference lines 8-11 on page 9 of Company witness Bransky's direct testimony, which states that the costs for security controls at the Phase I substations are higher than originally anticipated. Please answer the following:

(a) Please provide the initial estimated cost and actual (or projected) cost for each of the Phase I substations.

(b) Please explain what is meant by costs being higher due to "additional costs to prepare the substation for the physical security improvements."

Response:

(a) The initial estimated cost and actual (or projected) cost for each of the Phase I substations are:
- Substation A: The estimate was $1,200,000. A second estimate was completed before the project was released to construction which came in at $1,995,000. The actual cost for the project was $3,149,393.
- Substation B: The project estimate was $3,000,000. The projected completion cost is $3,000,000.
- Substation C: The project estimate was $2,500,000. The projected completion cost is $2,500,000.
- Substation D: The project estimate was $420,000. The projected completion cost is $420,000.

(b) To realize the physical security improvements at the substations, the substation needs to be prepared to support the additional protections. Preparing the substation requires rearranging substation assets to support taller fences and egress of power lines from the substation as well as groundwork to remove rocks or relocate other facilities to support the anti-digging aspects of the new fencing. As part of this preparatory work, there are required relocations of existing distribution equipment such as poles, conduits, and duct banks.

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<u>Virginia Electric and Power Company</u>
<u>Case No. PUR-2021-00127</u>
<u>Virginia State Corporation Commission Staff</u>
<u>Seventh Set</u>

The following response to Question No. 123 of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff and received on August 19, 2021 has been prepared under my supervision.

Richard C. Siepka
Manager, Electric Distribution Grid Planning
Dominion Energy Virginia

Question No. 123

Please reference pages 16-17 of Company witness Wright's direct testimony, which references the need to substitute the Chase City voltage island for the St. John's voltage island. Please answer the following questions:

(a) Please explain the rationale for the need to substitute Mainfeeder 42535 with Mainfeeder 26340.
(b) Please describe any changes the Company has made to the voltage island mitigation program as a result of lessons learned from Phase I.
(c) Please describe any changes the Company has made to the voltage island mitigation program to help reduce the probability that other projects would require future substitution.

Response:

(a) The Company assumes that Staff intended to ask the rationale for the need to substitute the Chase City voltage island for the St. John's voltage island.

As part of pre-construction activities for St. John's voltage island, the Company encountered land acquisition and permitting issues for which the Company was not able to identify an alternative timely solution. As noted by Company Witness Wright, the Commission granted the Company's motion to substitute the St. John's voltage island with the Chase City voltage island on June 14, 2021 in Case No. PUR-2019-00154.

(b) As a result of lessons learned from Phase I, the Company performed preliminary assessments of the remaining 13 voltage islands to be addressed over the 10-year GT Plan to determine if existing substation footprints support the addition of additional substation transformers. In cases where substation expansion appears likely and additional land would need to be procured, the Company extended the project timelines.

(c) See response to (b)

Virginia Electric and Power Company
Case No. PUR-2021-00127
Virginia State Corporation Commission Staff
Seventh Set

The following response to Question No. 125 of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff and received on August 19, 2021 has been prepared under my supervision.

Richard C. Siepka
Manager, Electric Distribution Grid Planning
Dominion Energy Virginia

Question No. 125

Please refer to the Company's response to Staff's Interrogatory Question No. 70. Please describe the additional features/capabilities the Company plans to implement into the hosting capacity tool by the end of 2021.

Response:

By the end of 2021, the Company will add hosting capacity information for net metering installations, such as DER hosted on a customer's premises. This addition will include service transformer sizing into the hosting capacity calculation.

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Virginia Electric and Power Company
Case No. PUR-2021-00127
Virginia State Corporation Commission Staff
Ninth Set

The following response to Question No. 129 of the Ninth Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff and received on August 31, 2021 has been prepared under my supervision.

Nathan Frost
Director – New Technology & Energy Conservation
Dominion Energy Virginia

Question No. 129

Please refer to the Company's response to Staff's Interrogatory Question No. 126 which stated that solar interconnections average approximately 325 business days to issue a completed SGIA. Please answer the following questions:

(a) Does the 325 business days include those projects which are interdependent and thus are waiting for a project ahead of them to complete?

(b) If so, what is the average number of business days to issue a completed SGIA for only those projects where no initial interdependency had been identified?

Response:

(a) Yes, the average of 325 business days includes those projects which are interdependent and thus are waiting for a project ahead of them to complete.

The Company notes that the average number of days from when projects in this data set reach a Project A status to the interconnection agreement being sent to the customer is 264 business days.

(b) The average number of business days from application to issuance of a completed SGIA for only those projects where no initial interdependency had been identified is 300 business days.