Virginia State Corporation Commission
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Case Number (if already assigned) PUR-2021-00127

Case Name (if known) 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

Document Type EXTE

Document Description Summary Direct Testimony of Paul J. Alvarez submitted on behalf of Environmental Respondent

Total Number of Pages 76

Submission ID 22826

eFiling Date Stamp 9/13/2021 4:18:48PM

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September 13, 2021

VIA ELECTRONIC FILING

Mr. Joel H. Peck, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

RE: 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

Dear Mr. Peck:

Enclosed for filing in the above-captioned matter is the Direct Testimony of Paul J. Alvarez, which is being submitted on behalf of Appalachian Voices ("Environmental Respondent"). Included with this testimony are Mr. Alvarez's one-page summary and 2 attachments. This filing is being completed electronically, pursuant to the Commission's electronic document filing system.

Pursuant to Rule 140 of the Commission's Rules of Practice and Procedure, Environmental Respondent is providing service of documents in this case exclusively via email unless parties request otherwise. Please let me know if you do not agree to electronic service and would like to receive hard copies of documents.

If you should have any questions regarding this filing, please do not hesitate to contact me at (434) 977-4090.

Regards,

Nathaniel Benforado

cc: Parties on Service List
Commission Staff

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PETITION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	
	)	Case No. PUR-2021-00127
For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia	)	
	)	

SUMMARY OF

DIRECT TESTIMONY OF

PAUL J. ALVAREZ

ON BEHALF OF

ENVIRONMENTAL RESPONDENT

Public Version

September 13, 2021

<u>**Summary of the Testimony of Paul J. Alvarez**</u>

Environmental Respondent Witness Paul J. Alvarez presents the results of his examination of Dominion's Phase 2 Grid Transformation Plan, which he conducted in close cooperation with his associate, Dennis Stephens, who is also an Environmental Respondent Witness. While Mr. Stephens's testimony addresses the details of specific Dominion project proposals, this testimony by Mr. Alvarez addresses several cross-cutting issues, including cost-benefit analyses and regulatory process improvement opportunities.

Mr. Alvarez's examination finds:

1. The Company has not sufficiently investigated opportunities to reduce plan costs;
2. The Plan is not cost-effective, as many projected benefits are significantly exaggerated;
3. The Plan sub-optimizes capabilities likely to reduce demand or energy use; and
4. The Plan includes almost no performance accountability.

As a result of these deficiencies, Mr. Alvarez recommends the Commission reject the Company's Phase 2 Grid Transformation Plan. However, in the event the Commission prefers to approve some portions of the Plan, Mr. Alvarez provides recommendations for specific Plan components with which he takes issue as an alternative to full rejection. Among these alternatives he recommends rejecting some programs as proposed, including the Customer Information Platform, the Telecommunications Network expansion, and the voltage optimization enablement program. He suggests additional data must be procured and analyzed for these, and also to more accurately estimate the economic impact of service outages on Virginia's economy. His alternative recommendations also include suggestions for maximizing the demand response and energy efficiency benefits from conservation voltage reduction and advanced metering; a mechanism for recognizing, in rates, those types of operational benefits customers miss out on between rate cases; and suggestions for dramatically increasing Plan performance accountability.

Mr. Alvarez's testimony also provides some suggestions for Commission consideration regarding regulatory process improvement opportunities. Mr. Alvarez identifies several deficiencies in the current process, including 1) stakeholder information and expertise asymmetry; 2) a litigation process and schedule ill-suited to the complexities of distribution planning; and 3) the practical elimination of cost disallowance risk. He recommends joint stakeholder/Company development of the next Phase of the Grid Transformation Plan as a way to mitigate deficiencies in the current process and alleviate pressure from the 6-month deadline for a final order in these types of proceedings.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

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

DIRECT TESTIMONY OF

PAUL J. ALVAREZ

ON BEHALF OF

ENVIRONMENTAL RESPONDENT

Public Version

September 13, 2021

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ATTACHMENTS

Attachment PJA-1	Curriculum Vitae (includes expert testimony list)
Attachment PJA-2	Discovery Responses

I. INTRODUCTION, QUALIFICATIONS, PERSPECTIVES, AND PREVIEW

Q: PLEASE STATE YOUR NAME, EMPLOYER, AND BUSINESS ADDRESS.

A: My name is Paul J. Alvarez. I am the President of the Wired Group, a boutique consultancy typically employed by consumer, business, and environmental advocates in utility regulatory proceedings. My business address is P.O. Box 620756, Littleton, Colorado 80125.

Q: PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE AS IT RELATES TO THIS DIRECT TESTIMONY.

A: My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now Android/Google), Baxter Healthcare, Searle Pharmaceuticals (now owned by Pfizer), and Option Care (now owned by Walgreens). My combined aptitude for finance and marketing were well suited for innovation and product development, leading to my first job in the utility industry in 2001 with Xcel Energy, one of the largest investor-owned utilities in the U.S.

At Xcel Energy, I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential, commercial, and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance (including distributed solar incentive program design and metering policies). There, I learned the economics of traditional monopoly ratemaking and associated utility incentives, as well as a great deal about utility program benefit quantification (measurement and verification, or "M&V").

In 2012, I started the Wired Group to focus exclusively on distribution utility business optimization. In addition, I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I have also taught at Michigan State University's Institute for Public Utilities, where I have educated new regulators and commission Staff on grid modernization and distribution utility performance measurement.

In addition, I am the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. The book helps laypersons understand smart grid capabilities, optimum designs, and post-deployment performance optimization, and is now in its 2nd edition. I am also the developer of the *Utility Evaluator*™, an Internet-based software program which benchmarks distribution utility performance against peers with like characteristics using publicly-available financial and operational performance data.

Regarding education, I received an undergraduate degree from Indiana University's Kelley School of Business in 1983, and a master's degree in Management from the Kellogg School at Northwestern University in 1991. Both degrees featured concentrations in Finance and Marketing.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A: I am submitting testimony on behalf of Appalachian Voices ("Environmental Respondent") in this proceeding.

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

A: This testimony presents the results of my examination of Dominion Energy Virginia's ("Dominion" or "Company") Phase 2 Grid Transformation Plan, conducted in close co-operation with Environmental Respondent witness Mr. Dennis Stephens. With some exceptions, my testimony generally presents policy positions and strategic considerations, as well as evaluations of the Plan's benefit-cost analyses, while Mr. Stephens's testimony goes into significant detail regarding specific Plan spending proposals. As a result, reviewers may wish to consider our testimonies together, and to consider reviewing this testimony before reviewing Mr. Stephens's testimony.

Q: HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE VIRGINIA STATE CORPORATION COMMISSION (THE "COMMISSION" OR "SCC") OR OTHER REGULATORY AGENCIES?

A: While this is my first testimony before this Commission, I have testified regarding grid planning processes, investment plans, prudence, cost recovery, and performance measurement before 15 other state utility regulatory commissions, including California, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, and Washington. Please see Exhibit PJA-1 for a complete list of my regulatory appearances and brief summaries of testimony. I have also served as a consultant to consumer, business, and environmental advocates participating in utility regulatory proceedings in six additional states, including Colorado, Florida, Hawaii, Michigan, South Carolina, and Virginia.

In addition, reviewers of this testimony are advised of a whitepaper I co-authored with Mr. Stephens in 2018, *Modernizing the Grid in the Public Interest – A Guide for*

Virginia Stakeholders.[1] Written on behalf of non-profit organization GridLab, the whitepaper was widely distributed and read in Virginia in advance of the Company's initial petition in Commission Case No. PUR-2018-00100.

Q: PLEASE PROVIDE ANY RELEVANT PERSPECTIVES YOU BRING TO THIS TESTIMONY AND YOUR ANALYSIS OF THE COMPANY'S PLAN.

A. The overall perspective I bring to this testimony is a belief that rate increases are a precious resource, to be spent only with exceptional care and consideration. The ability of Virginia's economy to accommodate rate increases without harm is finite and a utility asking for dollars from its customers bears the heavy burden of establishing such costs are no higher than necessary. Any utility spending proposals should represent the highest and best possible use of funds and should be accompanied by plans for optimizing spending increases in a way which maximizes customer economic benefits and environmental benefits. I believe the more wisely Dominion invests capital, and the more vigorously Dominion pursues available benefits from such spending, the greater the environmental and economic benefits the Commonwealth will secure per dollar of rate increase.

As the Commission is well aware, Virginia is at the starting point of a very long and multi-faceted clean energy journey. In just the past several years, the Virginia General Assembly has passed important and necessary legislation paving the way for this carbon-free electricity transition. These new laws, including the Virginia Clean Economy Act and Virginia's emissions reduction program, impose significant requirements on the Company and come with a cost.

[1] Paul Alvarez and Dennis Stephens, *Modernizing the Grid in the Public Interest – A Guide for Virginia Stakeholders*, GridLab (Oct. 5, 2018), https://gridlab.org/publications/.

Against this backdrop, it is important that all requests for cost recovery receive a high-level of scrutiny—especially those costs that are not statutorily mandated. If rate increases are a finite resource, like an automobile's tank of gas, I believe Virginia should keep as much gas in that tank as possible, thereby increasing the likelihood that the clean energy journey will be completed before available fuel in the tank (rate increases) is exhausted. Appropriate spending prioritization, including decisions to postpone some spending until needs become clearer, and more certain, should be viewed as essential.

Q: WHAT DOES THIS PRIORITIZATION MEAN IN TERMS OF THE DISTRIBUTION GRID PLANNING AND INVESTMENT?

A: Grid transformation investments are not statutorily required and thus, it is especially important to prioritize the risks that these proposed investments are aimed to address. Risks to be prioritized in this context include:

- The risk that the distribution grid can accommodate increases in clean distributed energy resource interconnections without significant delays;
- The risk that transportation electrification can be accommodated without significant delays;
- The risk that the transmission grid can safely and reliably accommodate increases in clean utility-scale generation without significant delays; and
- The risks to short-term health and long-term climate impacts associated with continued operation of coal-fired (and, eventually, natural gas-fired) generation.

Today, Dominion makes all the choices, including the priorities assigned to each risk and the best (capital-intensive) mitigation approaches for each. Given Dominion's capital bias,[2] not to mention the incentive to avoid customer refunds presented by the Grid Transformation Security Act ("GTSA"),[3] the Commission should carefully scrutinize these proposals, just as it has done in Phase 1a and 1b. Moreover, greater stakeholder participation in distribution planning and investment decisions, both traditional and new, is warranted. To participate responsibly, I believe stakeholders must build competencies in risk prioritization and mitigation, as well as in distribution planning and operations.

Q: DO YOU PERCEIVE REGULATORY PROCESSES IN VIRGINIA TO BE A ROADBLOCK TO OPTIMAL DISTRIBUTION PLANNING AND INVESTMENT DECISIONS?

A: Yes, I do. I identify three primary deficiencies in the regulatory process used to consider utilities' GTSA proposals, including: 1) stakeholder information and expertise asymmetry; 2) a litigation process and schedule ill-suited to the complexities of distribution planning; and 3) the elimination of cost disallowance risk.

Q: PLEASE BRIEFLY EXPLAIN EACH OF THESE PERCEIVED DEFICIENCIES

A: As is abundantly clear from Mr. Stephens's testimony, a deep understanding of electricity distribution planning processes, operations, standard practices, technologies, and more are required to properly evaluate highly technical utility proposals. Such understanding is in short supply, as experts like Mr. Stephens typically work for utilities, their suppliers, or their consultants. Stakeholder information and expertise asymmetry in electricity distribution must be addressed, ideally through education over time, likely in a manner

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[2] By "capital bias" I mean the shareholder incentive to grow the rate base as large as possible since Dominion earns a return on the size of the rate base.

[3] 2018 Va. Acts, ch. 296.

similar to Virginia's experiences in resource plan and demand-side management plan development in recent years.

Further, the litigation process is ill-suited to the complexities of distribution planning, risk assessment and mitigation, investment, and performance measurement. Given stakeholder information and expertise asymmetry, compounded by the complexity of the issues and the legal considerations of utilities and intervenors, a few rounds of discovery simply do not provide sufficient opportunity for GTSA Plan investigation and understanding, let alone to meet stakeholders' educational needs as described above. I submit that a different and more participatory approach to GTSA plan development is warranted. The compressed timeframe prescribed by the GTSA only makes matters worse.

Finally, the GTSA requires that the prudence of planned spending be determined in advance. Thus, once the Commission approves a GTSA plan, cost disallowance risk effectively falls to zero. This fact, combined with stakeholder information expertise asymmetry and a compressed litigation schedule, encourages utilities to propose greater investments than they otherwise would. In the absence of cost disallowance risk, the record indicates that utilities make riskier investments, and investments of less obvious benefit and necessity, than when prudence is examined after investments are made[4] (the traditional approach).

Of course, many of the causes of these do not arise from the Commission itself, but instead from statutory language. Nonetheless, I believe the Commission does have

[4] Paul Alvarez, et al., *Regulation through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities*, Vol. 34, The Electricity Journal 107005 (Oct. 2021).

discretion to alleviate some of these issues. I will return to these issues in the Recommendations section of this testimony.

Q: PLEASE PROVIDE A PREVIEW OF THIS TESTIMONY AND ITS ORGANIZATION.

A: The remainder of my testimony is organized as follows:

II. Opportunities to Reduce Plan Costs Have Not Been Sufficiently Investigated

III. The Plan Is Not Cost-Effective; Many Benefits Are Significantly Exaggerated

IV. Capabilities Likely to Reduce Demand or Energy Use are Sub-Optimized

V. Dominion's Plan Includes Almost No Performance Accountability

VI. Recommendations

Q: ARE YOU SUBMITTING ATTACHMENTS ALONG WITH YOUR TESTIMONY?

A: Yes, my Curriculum Vitae is provided as Attachment PJA-1, as well as referenced discovery responses collected in Attachment PJA-2.

II. OPPORTUNITIES TO REDUCE PLAN COSTS HAVE NOT BEEN SUFFICIENTLY INVESTIGATED

Q: PLEASE PROVIDE A PREVIEW OF THIS SECTION OF TESTIMONY

A: In this section I will describe opportunities to reduce Plan costs that Dominion has not sufficiently investigated, including those associated with:

(1) Dominion's $233 million Customer Information System Proposal; and

(2) Dominion's $290 million Telecom Networks Proposal.

(1) Dominion's $233 Million Customer Information System Proposal

Q: WHAT ARE YOUR CONCERNS REGARDING DOMINION'S $233 MILLION CUSTOMER INFORMATION SYSTEM PROPOSAL?

A: My primary concern is that Dominion has not examined opportunities to reduce the cost of a new customer information system. I understand the GTSA specifically defines customer information platforms as an Electric Distribution Grid Transformation Project, thus qualifying for the Customer Credit Reinvestment Offset ("CCRO") mechanism.[5] However, this does not relieve the Company of its obligation to evaluate opportunities to secure modern utility customer information system ("CIS") software at the least possible cost. In discovery, Dominion admitted it had not evaluated alternatives to its $233 million CIS proposal.[6]

Q: WHAT ARE THE POTENTIALLY LESS COSTLY ALTERNATIVES TO THE COMPANY'S $233 MILLION CIS PROPOSAL?

A: The most popular form of software administration today is distributed data processing, also known as "software as a service" or "SAAS". In SAAS, software is not purchased as a capital asset, nor installed on the capitalized hardware in a utility's own data center, nor upgraded over time through the purchase and installation of newer versions, nor maintained by utility information technology employees. Instead, all of these services are provided by software developers as a service, rented over time as an operations and maintenance expense rather than purchased and capitalized in the rate base. Microsoft, Oracle, SAP, and Salesforce are just a few of the leading global software developers with

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[5] Va. Code § 56-576.

[6] Company's Response to APV Set 2-61(i).

significant or majority portions of revenues from SAAS, and almost all of the major purveyors of utility customer information systems offer a SAAS option.

Importantly, O&M spending, even when more expensive than capital costs from a utility's perspective, can be less expensive to customers, owing to the carrying charges (utility profits, income taxes on profits, interest expense, etc.) customers must pay on utility capital.

Q: DID DOMINION EXPLAIN WHY IT DID NOT COMPARE THE COST OF SAAS TO TRADITIONAL SOFTWARE LICENSING APPROACHES?

A: Yes. The Company states that it "reviewed industry best practices of utilities of similar size".[7] Given that utilities of the Company's size in the U.S. are all investor-owned, and given that almost every investor-owned utility is subject to capital bias, the fact that other utilities of Dominion's size pursue traditional software licenses over SAAS does not mean that the proposed CIS purchase is the best option for customers, and it certainly does not excuse Dominion's failure to complete a cost comparison. Further, Dominion states that it considered "what is commercially available".[8] Yet even the specific CIS platform Dominion selected[9] is available from the supplier in the SAAS option.

(2) Dominion's $290 Million Telecommunications Network Proposal

Q: WHAT ARE YOUR CONCERNS REGARDING DOMINION'S $290 MILLION TELECOMMUNICATIONS NETWORK PROPOSAL?

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[7] *Id.*

[8] *Id.*

[9] *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 (June 21, 2021) at Filing Schedule 46 E, Confidential Attachment "Provider A", page 7.

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A: While I have several concerns, the largest of these by far is cost. Dominion's proposal involves extending high-speed connectivity to additional critical facilities (generally, substations) through Company-owned fiber and microwave facilities. As with SAAS, these high-speed data services are available in both capitalized purchase and rental (operations and maintenance expense) formats. Dominion's own expert estimates that the cost to rent telecommunication network services over the expected useful life of the owned equipment was just $93.5 million[10] – a savings of more than 2/3rds, or almost $200 million, relative to the owned option proposed by the Company ($290 million, not including carrying charges customers will be asked to pay over the life of the assets). Further, as an operations and maintenance expense, customers incur zero carrying charges on rental costs.

Q: DID THE COMPANY EXPLAIN WHY IT PREFERRED OWNED NETWORKS TO RENTED NETWORKS?

A: Yes. Dominion claims that owned networks are more reliable than rented networks, but refused to provide data in support of this claim in discovery, citing security concerns.[11] Moreover, even if there were evidence to support this claim (which Dominion has not provided), it is doubtful that the difference in reliability is worth the extra $200 million, nor did Dominion claim such a value in discovery.

Q: DO YOU HAVE OTHER CONCERNS REGARDING THE COMPANY'S TELECOMMUNICATIONS NETWORK PROPOSAL?

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[10] Direct Testimony of Andrew L. Trump, *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 (June 21, 2021) ("ALT Testimony") at Schedule 2, p. 42, tbl. 45.

[11] Company's Response to APV Set 2-35(a) and (b).

A: Yes. The Company claims its telecommunications proposal will bring high-speed communications services to rural areas without such services. However, the Company admitted in discovery that it had not overlaid the proposed network expansion against underserved areas in Virginia.[12] As a result, there can be no certainty that the Phase 2 parts of the Company's telecommunications expansion will in fact deliver high-speed communications to any areas without such services, nor has the Company included any revenues from the sale of high-speed communications capacity in its cost or benefit estimates. Finally, the Company reports that construction of its high-speed communications services in Surry County, Botetourt County, and the Northern Neck Region has not yet been completed,[13] meaning that the results of the pilot approved by the Commission in Case No. PUR-2020-00125 are not yet known.

III. THE PLAN IS NOT COST EFFECTIVE; MANY BENEFITS ARE SIGNFICANTLY EXAGGERATED

Q: PLEASE PROVIDE A PREVIEW OF THIS SECTION OF TESTIMONY

A: In this section I will describe instances of exaggerated benefits in the Company's benefit-cost analysis. Given that the Company estimates an extremely narrow benefit-to-cost ratio of just 1.05 to 1 in present value terms—indicating that any combination of cost overruns or underdelivery of benefits amounting to just 5% will result in a negative benefit-to-cost ratio to customers—these exaggerated benefits are troubling. Exaggerated benefit examples I will describe include:

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[12] Company's Response to APV Set 2-37(a).

[13] Company's Response to APV Set 2-37(b).

(1) The Interruption Cost Estimator tool Dominion used to translate reliability improvements into economic benefits exaggerates economic benefits;

(2) Benefits from voltage optimization enablement are not assured, and are inappropriate for inclusion in the Plan benefit-cost analysis in any event;

(3) Operations and Maintenance reductions from multiple sources are not backed by headcount reduction plans, nor are they estimated using avoided marginal costs; and

(4) The Company's approach to estimating avoided future capital from its Enterprise Asset Management System are disingenuous.

(5) The Company's consideration of additional quantified and qualified benefits is inappropriate, as additional quantified and qualified costs are ignored completely.

(1) The Interruption Cost Estimator tool Dominion used to translate reliability improvements into economic benefits exaggerates economic benefits.

Q: WHAT IS THE INTERRUPTION COST ESTIMATOR TOOL, AND HOW DID DOMINION USE IT TO ESTIMATE THE ECONOMIC BENEFITS OF PROJECTED RELIBILITY IMPROVEMENTS?

A: The Interruption Cost Estimator ("ICE") is an online application sponsored by the US Department of Energy. In response to a limited number of inputs, the tool delivers an estimate of the economic benefits of specified reliability improvements that associated investments will deliver over the life of the associated assets. These inputs include customer counts by class, estimated reductions in outage duration ("SAIDI") and frequency ("SAIFI"), estimated useful life of equipment, and the discount rate to be used for translating nominal benefits over time into present value, among others. Dominion provided the ICE model with projected reliability improvements and other Dominion-specific data, and used the resulting ICE economic benefit outputs in Plan benefit-cost analyses.

Q: HOW DOES THE ICE TOOL EXAGGERATE THE ECONOMIC BENEFITS TO CUSTOMERS OF RELIABILITY IMPROVEMENTS?

A: The ICE tool exaggerates the economic benefits from reliability improvements in two ways. First, estimates of customer outage costs on which ICE relies were collected through surveys that were never intended to be used to estimate the economic impact of outages over a defined geography, such as a state or a utility service territory. Instead, the U.S. Department of Energy found some outage cost data a few utilities had collected by survey—in some cases more than 30 years ago—and hired consultants to make use of the data in the development of the ICE tool. Second, the surveys were not collected in a statistically or sociologically valid manner. ICE tool deficiencies make it inappropriate for use in making grid investment decisions amounting to hundreds of millions of dollars.

Q: WHY CAN'T OUTAGE COST DATA COLLECTED FROM CUSTOMERS BE USED TO ESTIMATE THE ECONOMIC IMPACT OF OUTAGES OVER A DEFINED GEOGRAPHY?

A: In essence, the ICE tool adds up the costs of outages to individual customers and proclaims this to be the avoided cost benefit associated with reliability improvements. It is inappropriate to simply aggregate the outage costs estimated by individual customers to approximate the economic impact of outages across a service area, or even a circuit. Consider a residential customer, faced with no electricity for cooking and air conditioning, who decides to go out to dinner, or to a shopping mall. Such an outage would actually benefit some businesses and the local economy. Or, consider a motorist who drives past one gas station without power and stops at a gas station a few miles away with power. While one business lost revenue, another business gained revenue, resulting in no net economic loss to the community as a whole. The ICE tool does not take these offsetting impacts into account in any way.

Q: WHAT IS WRONG WITH THE WAY THE CUSTOMER OUTAGE COST DATA WAS COLLECTED?

A: The manner in which the surveys were administered resulted in several types of bias in data collected from commercial and industrial ("C&I") customers. Multiple problems associated with survey administration which serve to exaggerate ICE tool economic benefit estimates from reliability improvements include:

- The surveys were limited in number, conducted decades ago, and collected data only from C&I customers in manufacturing and retail businesses (now a minority among non-residential customer classes). This is known as selection bias.
- The identities of the surveyors—*i.e.*, utilities—were known to the C&I customers, which likely biased responses from respondents hoping for financial renumeration. This is known as response bias.
- The 14 survey projects were not geographically representative, completed in just five US geographies, and it is not known if any of these were conducted in Virginia. This is known as geographic bias, a particular type of selection bias.
- There is no consistency in how survey respondents were instructed to take back-up generation and uninterruptible power supplies into account when completing

surveys. It is inappropriate to combine the results of surveys in which respondents received different instructions, particularly regarding a survey element so critical to the question the ICE tool is meant to answer (the economic cost of service outages).

Q. HOW CRITICAL IS THE TRANSLATION OF RELIABILITY IMPROVEMENTS INTO ECONOMIC BENEFITS IN DOMINION'S BENEFIT-COST ANALYSES?

A: The ICE-generated benefits is the most significant assumption in Dominion's benefit-cost analysis. Between Grid Infrastructure and Grid Technology investment categories, the purported economic benefits of reliability improvements for customers represent the single largest benefit type by far, accounting for over half of all benefits in the benefit-cost analysis in both nominal and present value terms.

(2) Benefits from voltage optimization enablement are not assured, and inappropriate to include in the benefit-cost analysis in any event.

Q: WHY ARE BENEFITS FROM VOLTAGE OPTIMIZATION ENABLEMENT NOT ASSURED?

A: As described in Mr. Stephens's testimony, Dominion's plan to spend $442 million to improve grid locations with low voltage (voltage optimization enablement) is just the first step in preparation for voltage reductions, which in turn would result in energy reductions. As Mr. Stephens describes, this first step is incredibly costly, and taken alone will not actually benefit customers and may in fact *increase* overall voltage and costs.

In the second step, Dominion must change the settings of load tap changers and voltage regulators at the head end (substation) of every circuit, reducing the voltage from the current average (123 volts)[14] by 1.67% (down to 121 volts) to secure a 1% energy reduction.[15] There are no assurances Dominion will take this second step, and no proposed reporting measures to ensure the step is both taken and maintained. A lack of reporting also makes it impossible to ensure continuous voltage reduction improvements are secured over time.

Q: WHY WOULD DOMINION NOT TAKE THE SECOND STEP TO REDUCE VOLTAGE FROM THE SUBSTATION TO SECURE ENERGY SAVINGS?

A. Dominion ratemaking is subject to the throughput incentive. Though a vast oversimplification, during the ratemaking process, a utility's revenue requirement is divided by expected sales volumes to determine a rate per unit of measure (dollars per kilowatt hour). If the utility sells the expected volume of kilowatt hours, it will secure its revenue requirement; however, if the utility sells less than the expected volume, it will come up short of the revenue requirement. Dominion will therefore be economically penalized for reducing voltage because it will reduce energy sales. As a result, it is unlikely the Company will take the second step without enforcement and reporting efforts. I will address these topics later in my testimony.

Q: WHY ARE BENEFITS FROM VOLTAGE OPTIMIZATION ENABLEMENT INAPPROPRIATE TO INCLUDE IN THE PLAN'S BENEFIT-COST ANALYSIS?

A: In short, because the $442 million in investments Dominion wishes to make are not required to deliver benefits from simple voltage reduction actions Dominion can likely take at the head ends of circuits (load tap changers and voltage regulator settings) upon advanced metering infrastructure ("AMI") deployment.

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[14] Company's Response to APV Set 2-23(d).

[15] Company's Response to APV Set 2-7(c).

Q: PLEASE EXPLAIN HOW DOMINION COULD SECURE VOLTAGE REDUCTION BENEFITS WITHOUT SPENDING $442 MILLION ON "ENABLEMENT".

A: As described in Mr. Stephens's testimony, circuit voltages are set somewhat higher than necessary at each circuit's head-end due to a phenomenon known as voltage drop. This measure is taken as a precaution against customers at the ends of circuits experiencing exceptions below the minimum voltage standard (110 volts). With AMI, Dominion will have voltage data from hundreds if not thousands of points along each circuit, reducing the level of precaution needed due to the vastly improved awareness AMI offers of any customer voltage exceptions that might occur (assuming Dominion actually uses this AMI capability). This enhanced awareness enables utilities to be more aggressive with voltage level settings at the head end, allowing Dominion to reduce voltages to some extent at many if not most circuits without fear of unknowingly creating voltage exceptions for customers at the ends of feeders. *Dominion need not spend any capital at all to take such actions as the AMI deployment and associated voltage monitoring improvements proceed.* As my position is that voltage optimization enablement spending is not required to secure energy savings, the program should be rejected, and both costs and benefits from voltage optimization enablement should be removed from the cost-benefit analysis.

Q: HOW CRITICAL IS THE VOLTAGE OPTIMIZATION ENABLEMENT BENEFIT ESTIMATE IN DOMINION'S BENEFIT-COST ANALYSES?

A: Dominion estimates the benefits from voltage optimization enablement at $2.4 billion over 40 years, making it the second largest source of benefits (second only to the economic benefits from reliability improvements) in Dominion's benefit-cost analysis. Voltage optimization benefits are therefore extremely critical to Dominion's claim that its Plan delivers benefits in excess of cost.

(3) Operations and Maintenance reductions from multiple sources are not backed by headcount reduction plans, nor are they estimated using marginal costs.

Q: PLEASE EXPLAIN HOW THE COMPANY ESTIMATES OPERATIONS AND MAINTENANCE REDUCTIONS IN ITS COST-BENEFIT ANALYSES.

A: In some cases, the Company estimates operations and maintenance (O&M) savings in the manner one would expect. That is, by estimating headcount reductions and multiplying the headcount reductions in the department by average salaries and benefits for the department. Average vehicle costs avoided per headcount are also part of these benefit estimates. Dominion estimates savings in meter reading and meter services departments from AMI, for example, by projecting dramatic headcount reductions in those departments.

In many other cases, however, Dominion estimates O&M savings through reductions in activity levels, not headcount reductions. As I will address later in this testimony, such an approach mistakenly conflates a process measure, such as truck rolls or calls into a call center, with outcomes measures, such as O&M cost reductions secured through headcount reductions. There is a big difference between the two, as there are no assurances that reductions in activity levels will result in reductions in O&M costs or headcount. Further, utilities typically calculate activity-based O&M savings estimates on a fully-loaded cost per activity, not a marginal cost per activity. Fully-loaded costs per activity are calculated simplistically, for example (values are hypothetical):

$$\frac{\$9.3 \text{ million annual call center cost}}{3 \text{ million calls annually}} = \$3.10 \text{ cost per call}$$

This approach to activity-based costing is not appropriate for estimating O&M savings, as many O&M costs are fixed in nature and do not vary with activity volume. The costs which vary with activity volume are called marginal costs; these costs rise and fall with activity volume and are substantially smaller than fully-loaded costs. Activity-based cost reductions estimated using fully-loaded costs per activity exaggerate the actual level of cost reductions achievable. Dominion confirms this by refusing to commit to headcount reductions associated with activity-based O&M savings estimates in discovery.[16]

Q: HOW CRITICAL ARE ACTIVITY-BASED O&M SAVINGS ESTIMATES TO DOMINION'S BENEFIT-COST ANALYSIS?

A: Table 1 provides the O&M savings benefits Dominion estimated using activity-based reductions and fully loaded costs in various parts of the Phase 2 Plan. None of these estimates are based on headcount reductions, nor are they based on marginal costs avoided. At a total benefit of estimate of $196.9 Million, the O&M savings exaggerations are smaller than those from reliability improvements and voltage optimization enablement, but still significant.

[16] Company's Responses to APV Sets 2-44(b); 2-45(c); 2-46; 2-51(b); and 2-57.

Table 1: O&M savings estimated through activity reductions and fully-loaded costs per activity

Plan Component	Activity Reduction	O&M savings estimate over asset life (nominal)	Source
AMI	Reduced truck rolls due to avoided "OK upon Arrival" calls, net meter installations, and voltage investigations.	$41.8 million	Andrew L. Trump Testimony, Schedule 2, Table 1, pg. 2.
	Reduced calls to the call center	29.9 million	
Mainfeeder Hardening	Reduced feeder maintenance and reduction in truck rolls to restore service after outages	58.2 million	Andrew L. Trump Testimony, Schedule 2, Table 15, pg. 16
EAMS	Reduced labor in design, engineering, planning, project management, and others	61.9 million	Andrew L. Trump Testimony, Schedule 2, Table 30, pg. 27
Targeted Corridor Improvement	Reduced volume of outages to repair from enhanced vegetation management	5.1 million	Andrew L. Trump Testimony, Schedule 2, Table 18, pg. 19
	Total:	$196.9 million	

Q: DO YOU HAVE OTHER CONCERNS REGARDING THE COMPANY'S O&M SAVINGS ESTIMATES?

A: Yes. I am concerned about the degree to which O&M savings will be recognized as customer rate reductions, as well as the timing of such reductions. While the Company presents O&M savings in its benefit-cost analysis as economic benefits delivered ratably over time, customers do not secure O&M savings in this manner. Instead, customers only recognize O&M savings as rate reductions when updated O&M spending levels are presented in a rate case. Until such time, O&M savings from Plan investments will accrue to shareholders, not ratepayers. This is true not only for any O&M savings benefits from the sources presented in Table 1 above, but for other, even larger O&M reductions, such as in meter reading and meter services departments. Given rate cases only occur every three years, and the number of restrictions already imposed on the Commission that prevent traditional ratemaking, it is possible for such savings to be denied to customers for years. These dollars can be significant. For example, the Company estimates annual steady-state savings reductions from meter reading and meter services departments alone at $16.5 million annually.[17] If no rate case is held for three years, benefits missed by customers could amount to $50 million.

Q: IS THIS PHENOMENON APPLICABLE TO OTHER TYPES OF BENEFITS THE COMPANY ESTIMATES?

A: Yes. The phenomenon applies to any type of benefit which requires a rate case to recognize said benefit in rates. AMI-related examples include reductions in the bad debt accrual rate, increases in billed sales from improved theft detection, and increases in billed sales due to improved meter accuracy. Combined, this amounts to another $13.6 million in estimated steady-state benefits annually,[18] or an additional $40 million in missed benefits assuming a three-year wait between rate cases.

Q. HOW HAVE OTHER STATES' UTILITY REGULATORS ADDRESSED THIS?

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[17] Direct Testimony of Andrew L. Trump, *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. 2021-00127 (June 21, 2021) ("ALT Testimony") at Schedule 2, tbl. 1, p. 1-2.

[18] *Id.* at 3.

A. Most have simply not identified or recognized this issue. In Ohio[19] and Oklahoma,[20] Commissions ordered that projected benefits be reflected as reductions in authorized grid modernization riders until such benefits are captured in a rate case. In Kentucky, the Commission ordered that a regulatory liability be established for benefits secured but missed by customers due to rate case timing.[21]

(4) The Company's approach to estimating avoided future capital from its Enterprise Asset Management System are disingenuous.

Q: WHAT CONCERNS DO YOU HAVE REGARDING THE COMPANY's ENTERPRISE ASSET MANAGEMENT SYSTEM BENEFIT ESTIMATE?

A: The Company's Enterprise Asset Management System ("EAMS") benefit estimate assumes a capital benefit of $23 million. This benefit estimate assumes that EAMS will extend the life of assets in the field, delaying the need for replacements. As Mr. Stephens explains, in practice, utilities have used EAMS only to *accelerate* the rate of field equipment replacement, thereby reducing the length of service of field equipment, not extending it.

(5) The Company's consideration of additional quantified and qualified benefits is inappropriate, as additional quantified and qualified costs are ignored completely.

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[19] Ohio Public Utilities Commission, Case No. 10-2326-GE-RDR. Stipulation and Recommendation (Feb. 24, 2012) at 6; Order Approving Stipulation (June 13, 2012).

[20] Oklahoma Corporation Commission, Case No. PUD 201000029. Joint Stipulation and Settlement Agreement (May 27, 2010) at 3; Order No. 576595 Approving Joint Stipulation and Settlement Agreement (July 1, 2010).

[21] Kentucky Public Service Commission, Case No. 2020-00349. Stipulation and Recommendation (June 30, 2021) at 12; Order Approving Stipulation and Recommendation (June 30, 2021).

Q. COMPANY WITNESS MR. TRUMP DESCRIBES ADDITIONAL QUANTIFIED AND QUALIFIED BENEFITS RESULTING FROM ITS PLAN. DID YOU CONSIDER THESE BENEFITS IN YOUR EXAMINATION OF THE COMPANY'S PLAN?

A: No, I did not, nor should the Commission.

Q: WHY SHOULDN'T THE COMMISSION CONSIDER THE ADDITIONAL QUANTIFIED AND QUALIFIED BENEFITS DESCRIBED BY MR. TRUMP?

A: A benefit-cost analysis compares benefits to costs. These comparisons should be "apples-to-apples", meaning that if a type of benefit is considered, the same type of cost should be considered. Considering a type of benefit, without considering the corresponding cost, is completely inappropriate.

Q: DID THE COMPANY AND HIS WITNESS CONSIDER ANY TYPES OF BENEFITS WITHOUT ALSO CONSIDERING CORRESPONDING COSTS?

A: Yes. The Company describes the intangible benefits of its plan, such as reduced greenhouse gas emissions, electric vehicle ownership savings, and job creation and follow-on benefits to the Virginia economy from its spending. While the Company considers these indirect benefits, it does not consider corresponding indirect costs. In other words, this is not an apples-to-apples comparison.

For example, consider the fact that the Company included economic development benefits in its benefits-cost analysis. While the Company's Plan will spur economic activity in some electric industry sectors, from vegetation management contractors to electrical engineering, all the other sectors of Virginia's economy pay for the associated rate increases. When benefits do not exceed rate increases, as I show to be the case with the Company's Plan, there are negative impacts to economic development and jobs across Virginia. These indirect costs—which could result in job losses, reductions in customer disposable incomes or food and medication budgets, and other negative effects on the economy—are not in Dominion's analysis. As it is inappropriate to consider indirect benefits without also considering indirect costs, the Commission should discount indirect benefits the Company claims.

IV. <u>CAPABILITIES LIKELY TO REDUCE DEMAND AND ENERGY USE ARE SUB-OPTIMIZED</u>

Q: PLEASE PROVIDE A PREVIEW OF THIS SECTION OF TESTIMONY

A: In this section of testimony, I will discuss demand response and energy conservation opportunities to provide economic and environmental benefits that are conspicuously absent from Dominion's Phase 2 Plan. I provide recommendations in this section for increasing the demand response and energy conservation potential not covered elsewhere in the testimony of Environmental Respondent's witnesses, including:

1) Best practices are missing from proposed time-of-use rate designs and offers;

2) Compliance with Green Button's Connect My Data standard is missing from Plan.

Q: ARE THERE OTHER OMISSIONS YOU'D LIKE TO MENTION BEFORE DISCUSSING THESE TWO ISSUES?

A: Yes. The Company's most egregious omission is the omission of systematic Conservation Voltage Reduction ("CVR"), which Mr. Stephens addresses in his testimony. With significantly greater conservation potential, lower implementation costs, and lower customer and environmental risk than Dominion's voltage optimization enablement proposal, I believe this omission to be extremely suspect.[22] Given that Dominion owns an unregulated subsidiary, Dominion Voltage Inc, which is dedicated to helping utilities implement systematic CVR, the omission is even more surprising. However, as Mr. Stephens covers this topic in detail, I will not repeat it here. Suffice it to say I strongly support Mr. Stephens's testimony on voltage optimization enablement and CVR.

In addition, I want to highlight earlier testimony, in which I describe another CVR-related benefit omission. As I explain, Dominion could likely secure some level of CVR benefit by integrating the voltage reporting features of AMI meters into a CVR approach that avoids Dominion's proposed $442 million voltage optimization enablement investment entirely. Those observations are clearly relevant to this discussion as well, but rather than simply repeating those concerns, I want to focus on time-of-use rate designs and offerings and Green Button's Connect My Data.

1) Best Practices Are Missing from proposed time-of-use rate designs and offers

Q: WHAT ARE YOUR CRITIQUES OF DOMINION'S PROPOSED TIME-OF-USE RATE DESIGNS AND OFFERS?

A: I have two primary critiques of Dominion's proposed time-of-use rate designs and offers. First, a best practice to increase the demand response from time-of-use rate designs

[22] *See* Direct Testimony of Nathan J. Frost, *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 (June 21, 2021) at 6:13-15 (Dominion witness Frost indicating that a voltage optimization plan will be part of the Company's next DSM filing). However, given the tight relationship between the proposed $442 million voltage optimization enablement proposal and CVR, as discussed at length in Mr. Stephens's testimony, I strongly recommend the Commission avoid considering the voltage optimization enablement proposal without a corresponding voltage optimization plan. The two interdependent projects can only be properly considered together.

enabled by AMI is missing. Second, best practices to increase participation in time-of-use rate designs through better approaches to consumer offerings are missing from the Plan.

Q: WHAT BEST PRACTICE IN TIME-OF-USE RATE DESIGNS IS MISSING?

A: Dominion proposes to offer a three-part time-of-use ("TOU") rate, including on-peak, off-peak, and super off-peak rates, with no critical peak price feature.[23] However, research shows that time-of-use rates without a critical peak price feature are far less effective than those with critical peak price features at reducing coincident system peaks.[24] As a disproportionate amount of capital is employed to accommodate coincident system peaks, failure to incorporate critical peak price features into TOU rate design represents a significant missed opportunity.

Q: WHAT ARE THE DRAWBACKS TO INCORPORATING A CRITICAL PEAK PRICING COMPONENT INTO TOU RATES?

A: The biggest drawback to incorporating a critical peak pricing component into TOU rates is customer resistance. Critical peak prices can frighten potential TOU rate participants away. With an Opt-In (voluntary) TOU rate offer of the type the Company has proposed, this can reduce customer participation. However, potential solutions to this issue are available.

Q: WHAT ARE THE POTENTIAL SOLUTIONS TO THE MARKETING CHALLENGE PRESENTED BY TOU RATES WITH CRITICAL PEAK PRICING FEATURES?

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[23] A critical peak pricing feature is the same in a TOU rate as it is in the peak-time rebate program the Company describes in its Plan for Time-Varying Rates: a notice issued on up to 10 days a year for a short-term spike in prices during an on-peak period in response to a coincident system peak demand event.

[24] Ahmad Faruqui & Jenny Palmer, *The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity*, Vol. 4, No. 1, EDI Quarterly (Apr. 2012).

A: One approach is to make the TOU rate with critical peak pricing features the default rate. The default rate is the rate on which all customers who do not make an affirmative choice otherwise ("Opting Out" to a different rate) are placed. If maximizing the economic and environmental potential of AMI is the goal, as I believe it should be, an Opt-Out (default) approach to TOU rates with critical peak pricing features delivers the highest participation rates. However, default approaches to TOU rates with critical peak pricing features have strong critics, particularly among consumer advocates. While any customer can always opt-out to a different rate plan, consumer advocates cite the difficulty of advising customers of their options and getting customers to exercise those options. It can be particularly difficult to reach the very types of customers most adversely impacted by TOU with critical peak price features, including low-income customers with few discretionary loads to shift (such as air conditioners and clothes dryers), as well as customers with medical needs. I sympathize with these concerns.

Q: IF TOU WITH CRITICAL PEAK PRICING SHOULD BE THE DEFAULT RATE, BUT THE DEFAULT APPROACH HARMS CERTAIN CUSTOMER GROUPS, WHAT OPTIONS REMAIN?

A: In my opinion, the best practice is universal Peak-Time Rebate ("PTR"). While the Company includes Peak-Time Rebate in its Plan for Time-Varying Rates, the Company's approach requires customers to register for the Peak-Time Rebate program. The registration requirement reduces participation rates. The Company's benefit estimate assumes that only 20% of customers will sign up for a Peak-Time Rebate Program. When I apply the term "universal", I am suggesting that any customer can earn a rebate for reducing usage on a critical peak demand day on a moment's notice with no advance registration. Mass and social media can be used to notify all customers of each critical peak demand day. While customer smart phone information (for text notifications) and e-mail addresses (for e-mailed notifications) are ideal, they are far from a PTR advance registration requirement.

Q: HOW WOULD THIS WORK IN PRACTICE?

A: The Company would simply apply to all customers the same algorithm (to determine rebate size) it was planning to apply only to registered participants. If a customer appears to have modified his or her usage on a critical peak event day as indicated by the algorithm, he or she earns the rebate. For maximum satisfaction and future effectiveness, a prompt notification (feedback) of rebates earned (by text or e-mail) is ideal. But again, while prompt feedback is ideal, is should not be used to require advance registration.

Q: WHAT ARE THE BENEFITS OF UNIVERSAL PEAK TIME REBATE?

A: In addition to maximizing participation, it involves no bill risk for any particular customer population. If a customer, including a low-income or medical needs customer, is unable to reduce usage in response to a critical peak event notification, there is no penalty. The same cannot be said for a TOU rate with a critical peak pricing feature. To me, universal Peak-Time Rebate offers the best balance given the constraints of the situation.

Q: WHAT ARE THE DRAWBACKS OF UNIVERSAL PEAK TIME REBATE?

A: Inevitably, a small proportion of customers who did not earn a rebate will receive one. Similarly, a small proportion of customers who did modify behavior may not be recognized by the algorithm, and therefore receive no rebate. While anathema to demand-side management professionals, I do not agree that this drawback outweighs the benefits of universal peak-time rebate. Remember, the goal as I see it is to maximize the economic and environmental benefits per dollar of utility investment. Universal peak-time rebate advances this goal. To disqualify the approach solely on the basis of measurement error amounts to throwing the baby out with the bathwater in my book.

Q: HAVE ANY OTHER STATES ENACTED UNIVERSAL PEAK-TIME REBATE?

A: Only Virginia's neighbor, Maryland. Maryland Staff developed and pushed the concept when its utilities were among the first to install AMI back in 2011. It required all utilities with AMI to offer universal peak-time rebate as a condition for cost recovery, and it is still in use today. Calvin Timmerman, retired Assistant Executive Director of the Maryland Public Service Commission Staff, whom some reviewers may know, deserves much of the credit.

2) Compliance with Green Button's Connect-My-Data standard is missing from the Plan

Q: WHAT IS THE CONNECT-MY-DATA STANDARD?

A: The Connect-My-Data standard was developed by non-profit organization Green Button to harmonize meter usage data formats, access protocols, and customer authorizations in a way that makes it easy for customers to choose the smart phone app or home energy management system provider of their preference to manage energy use. Customer choice and competition are almost always good things for consumers and the environment, and neither smart phone apps nor home energy management systems should remain the exclusive domain of utilities.

The beauty of Connect-My-Data standard compliance is that it maximizes the size of the market for home energy management services providers. If each utility maintained its own data access and customer authorization protocols, smart phone app developers would not be able to justify the development of individual approaches for each utility.

Q: HAS DOMINION PROPOSED TO USE THE CONNECT-MY-DATA STANDARD?

A: No. Without Connect-My-Data standard compliance, Dominion customers will effectively be denied access to a growing ecosystem of energy management service providers, solar system purveyors, energy efficiency contractors, and the like which could otherwise help Dominion customers achieve their energy-related economic and environmental goals.

Q: HAVE OTHER COMMISSIONS MANDATED CONNECT-MY-DATA STANDARD COMPLIANCE?

A: Yes. Commissions in California, Colorado, Illinois, New York, and Texas have all mandated that regulated utilities comply with the Connect-My-Data standard.

V. DOMINION'S PLAN INCLUDES ALMOST NO PERFORMANCE ACCOUNTABILITY

Q: MR. WOOMER'S TESTIMONY PRESENTS MULTIPLE EXISTING AND PROPOSED METRICS FOR MEASURING GRID TRANSFORMATION PLAN PERFORMANCE. HOW ARE THESE INADEAQUATE?

A: The Approved Phase 1 and Proposed Phase 2 metrics are deficient in multiple ways. Simply tracking metrics over time is of little value. My primary complaints include:

- Most metrics measure processes, not outcomes. To protect customers, the Commission should be concerned exclusively with outcome metrics.

- The metrics do not include baselines (starting points to be used as bases for comparison).
- The metrics do not include targets (outcome assumptions relied upon for approval).
- Three of the most critical metrics in the Company's Plan are missing entirely.

Q: WHAT IS THE DIFFERENCE BETWEEN AN OUTCOMES METRIC AND A PROCESS METRIC?

A: Only outcomes metrics can be used to determine whether or not a goal has been met. Process metrics are only indicators of progress. For each proposed metric, I recommend asking a single question: does the metric measure progress towards a goal, or the goal itself? If the answer is anything other than the goal itself, the metric is a process metric.

Q: CAN YOU WALK US THROUGH A FEW EXAMPLES?

A: Certainly. Let's examine a few metrics presented in Mr. Woomer's testimony to illustrate.[25] Consider the metric "# of truck rolls avoided"[26]. Is the goal to avoid truck rolls? No. The goal is to reduce field labor costs. Avoided truck rolls may be an indicator of reduced field labor costs, but it is not the same as a reduction in field labor costs. An outcomes metric would be "field service center headcount" or "annual field service center payroll".

Consider the metric "# of DERs Integrated into DERMS"[27]. Is the goal to integrate DERs into DERMS? No. The goal is to increase the DER hosting capacity on a circuit, or on all circuits collectively. DER integration into DERMS may be an indicator

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[25] Direct Testimony of Joseph A. Woomer, *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 (June 21, 2021).

[26] *Id.* at 18:12-16.

[27] *Id.* at 45:1-4.

of increased hosting capacity, but it is not the same as an increase in hosting capacity. An outcomes metric would be "DER hosting capacity in MW".

Q: ARE THERE OTHER BENEFITS TO USING OUTCOMES METRICS BEYOND IMPROVING PERFORMANCE ACCOUNTABILITY?

A: Yes. I believe the use of outcome metrics eliminates large numbers of process metrics, resulting in a fewer number of metrics to be tracked, reported, and examined.

Q: WHY ARE BASELINES CRITICAL TO PERFORMANCE MEASUREMENT?

A: Baselines serve as a basis of comparison. Let's continue with our examples. If the outcome metric is "field service center headcount", and the value measured is "200", there is no way to know how significant the value is. If the metric includes a baseline value of 205 field service center headcount, the ability to identify that virtually no progress has been made is readily apparent. If the metric includes a baseline value of 400 field service center headcount, the ability to identify that excellent progress has been made is readily apparent. Baselines are critical to performance measurement, and every outcome metric should include a baseline historical value for context.

Q: WHY ARE TARGETS CRITICAL TO PERFORMANCE MEASUREMENT?

A: Typically, decisions to approve an expenditure are based on some kind of result the organization requesting the approval has assumed or projected. In the case of the Company's Phase 2 Plan, these assumptions and projections can typically be found in the details of cost-benefit analyses. Every outcome metric should include a target based on the assumption or projection relied upon by the Commission in making a decision to approve the expenditure. For the record, Table 2 presents the SAIDI and SAIFI performance (without major event days) the Company has projected from its Plan.[28] Should the Commission reject aspects of the Company's Plan, the Commission should require the Company to revise the projections to reflect only approved projects, and these new values should serve as targets for the metrics "SAIDI" and "SAIFI".

Table 2: SAIDI and SAIFI performance projected from the implementation of the Company's Phase 2 Plan

	'19	'21	'21	'22	'23	'24	'25	'26	'27	'28	'29
SAIDI	138.3	138.3	137.1	135.8	131.8	127.4	121.1	117.1	113.6	110.2	107.9
SAIFI	1.228	1.228	1.221	1.211	1.182	1.151	1.093	1.052	1.017	0.988	0.967

Q: WHAT THREE CRITICAL METRICS ARE MISSING ENTIRELY FROM MR. WOOMER'S LIST?

A. Reductions in the voltage at which energy is delivered – which, as I detailed earlier, represent a full $2.4 billion in nominal Plan benefits – are not included in the list of metrics. As multiple witnesses' testimonies claim again and again, the Plan is "required" to accommodate growing levels of distributed energy resources ("DER"). Yet we do not know the DER capacity the Company's grid can accommodate today, nor the incremental DER capacity the Company's grid will be able to accommodate if its Plan is approved. The same can be said for electric vehicle charging capacity.

Q: WHAT DO YOU CONCLUDE ABOUT THE METRICS PRESENTED IN MR. WOOMER'S TESTIMONY?

A: With a dearth of outcomes metrics, no baselines, no targets, and three critical missing metrics, Mr. Woomer's metrics are largely worthless for holding the Company accountable for achieving the assumed or projected performance levels upon which the

[28] Company's Response to Staff Set 1-28, "Attachment Staff Set 01-28 (ALT)(Reliability).xlsx", Tab ICE Inputs (Layer 3).

Commission is relying when deciding whether to approve a proposed program expenditure or not.

Q: HOW SHOULD THE COMMISSION HOLD THE COMPANY ACCOUNTABLE FOR PLAN PERFORMANCE?

A: As implied above, the Commission should ensure there is a metric in place for the assumptions behind every critical benefit and rationale the Company uses to justify its Plan. To the extent the Commission deems it appropriate to approve a portion of these projects, I recommend that such approval be made expressly contingent on the Company actually achieving targeted metrics. In essence, the Commission's ruling would incorporate performance metrics into the plan that is being approved prospectively as reasonable and prudent. If the Company comes back to the Commission seeking recovery of actually-incurred plan costs in a future proceeding, such costs would only be viewed as presumptively reasonable and prudent if both (1) the costs were incurred as part of an approved project *and* (2) the Company demonstrates that it actually achieved the associated metrics incorporated into the approved plan. If the Company fails to achieve a particular metric, then the Commission would retain the discretion to disallow some or even all of such costs based on the evidence in that proceeding.

Notably, these metrics will require work to develop. I recommend that the Commission direct the Company to form a working group with Staff and other parties to develop a metric list, which can be presented in a future proceeding. This directive should further require that such metrics be outcomes based, incorporate a historical baseline, and include a specific target based on an assumption or projection relied on by the Commission in approving a particular project. The directive should also ensure that at least one outcome metric, including those currently missing (voltage, DER capacity, and EV capacity), be developed for every critical plan benefit or rationale.

VI. <u>RECOMMENDATIONS</u>

Q: PLEASE SUMMARIZE YOUR TESTIMONY.

A: Based on my examination of the Company's Phase 2 Grid Transformation Plan, I conclude:

- Dominion has failed to sufficiently investigate opportunities to reduce plan costs;
- The Plan is not cost-effective, with many benefits significantly exaggerated;
- Dominion has failed to optimize capabilities that are likely to reduce demand or energy use; and
- Dominion's Plan includes almost no performance accountability.

Q: PLEASE PROVIDE RECOMMENDATIONS RESULTING FROM YOUR TESTIMONY.

A: Based on these findings, I recommend the Commission reject the Company's Phase 2 Grid Transformation Plan. I do not believe the Company has justified these significant investments as a whole or individually, exaggerating benefits and failing to explore available alternatives.

To the extent the Commission elects to approve some aspects of the Plan, I would recommend only specific aspects be approved subject to express conditions. In such an event, I make the following alternative recommendations regarding specific elements of this testimony:

- *CIS Platform.* Reject, pending an analysis of the pros and cons—practical, technical, and economic—of the traditional approach to software licensing compared to the same pros and cons of the software as a service ("SAAS") option.
- *Telecommunications Network.* Reject all capital investments for which renting capacity offers reduced cost to customers over capital investment (estimated revenue requirements). Limit any investments where leased capacity is both unavailable and required to least cost options (for example, microwave instead of cable). Refrain from using rural broadband access as a deployment approval consideration until a comprehensive review of the results of the pilot deployment approved in Case No. PUR-2020-00125 can be completed.
- *Improving the accuracy of the estimate of economic benefits resulting from improvements in reliability.* I recommend Staff oversee one market research study (customer-based, bottoms up) and one econometric study (Commonwealth-based, top down). The market research study should be a formal "willingness to pay" study, in which the average acceptable rate increases associated with various reliability improvements, expressed in terms customers can understand, can be determined by customer class. The econometric study should determine the statewide economic impact of electric service interruptions of various sizes and durations. These data points can be used to more objectively complete cost-benefit analyses for reliability-related investment proposals.
- *"Missing" and/or "Exaggerated" Operational Benefits.* In addition to holding the Company accountable for achieving specific performance targets, as described previously, specific efforts are needed to address the rate-case timing issue, and the

fact that certain types of economic benefits are only recognized in rates after a rate case. Mechanisms to quantify benefits secured between rate cases, and therefore never recognized by customers due to the rate case timing lag, have been identified by other state utility commissions, and I recommend the Commission Order one of these as a condition of approval for projects to which such concerns apply.

- *Voltage Optimization Enablement.* Consistent with Mr. Stephens's testimony, I recommend this program be rejected. In its place, the Commission should require a comprehensive plan from the Company for implementing Conservation Voltage Reduction ("CVR") as soon as possible, but in no case later than the next DSM program application. The Commission should expect the following CVR plan components:
    - A plan for implementing CVR, including field equipment required per circuit and average cost per circuit (see Stephens's testimony for info), and incorporating AMI as a data resource for more aggressive CVR;
    - An estimate of the economic and environmental benefits per average circuit (the Commission should not accept anything less than a 4% voltage reduction);
    - A plan for identifying circuits for which CVR is likely to be cost-effective (through economic analysis);
    - A commitment to deploy CVR within two years on all circuits for which CVR is likely to be cost-effective; and
    - A comprehensive, ongoing performance reporting program for CVR by circuit to ensure management focus and continuous conservation increases over time.

- *Demand and Energy Use Benefit Maximization.* Require the Company to implement a universal peak-time rebate program, and require the Company to comply with the Connect-My-Data standard, as conditions of AMI approval.
- *Performance Reporting.* I recommend the Commission consider a fresh start to Grid Transformation metrics reporting based on the observations presented in this testimony. I believe a working group should be established to create a new metric list, in compliance with the following principals:
  - Every metric should be an outcomes metric, not a process metric;
  - Every metric should include a historical baseline value;
  - Every metric should include a target, consisting of the assumption or projection on which the Commission relied when deciding to approve the program; and
  - Metrics should exist for every critical benefit estimate and rationale provided, including those currently missing (Voltage at which energy is delivered; DER capacity; and EV charging capacity, at a minimum).
- *Mr. Stephens's Back-up Recommendations.* I note that Mr. Stephens also provides back-up recommendations in the event the Commission determines that his primary recommendation (outright Plan rejection) is inappropriate. I have reviewed and support all of Mr. Stephens's back-up recommendations.

Q: DO YOU HAVE RECOMMENATIONS FOR OTHER COMPONENTS OF DOMINION'S GRID TRANSFORMATION PLAN?

A: No. I take no position on components of the Grid Transformation Plan not addressed in this testimony, other than the endorsement of Mr. Stephens's recommendations as indicated above.

Q: DO YOU HAVE ANY OVERALL RECOMMENDATIONS TO SHARE?

A: Yes. Irrespective of the Commission's decision in this proceeding, I encourage the Commission to address the regulatory process deficiencies in GTSA Plan consideration I noted in the Introduction to this testimony. Please recall that these deficiencies, as I perceive them, include:

- Stakeholder information and expertise asymmetry;
- A litigation process and schedule ill-suited to the complexities of distribution planning; and
- The elimination of cost disallowance risk.

I believe these regulatory process deficiencies encourage Dominion to make larger investment proposals than it otherwise would, and lead directly to the frustrations the Company and Stakeholders experience in the "Dominion proposes Plan, Stakeholders oppose Plan" cycle in which Virginia seems to be mired. I note that while the GTSA authorizes Dominion to submit GTSA plans as often as annually, there is no requirement to submit plans annually. I suggest that the Commission establish a working group immediately upon its Order in this proceeding, the purpose of which would be to jointly develop the next Phase of the plan. As Staff, stakeholders, and the Company work through differences in goals, priorities, solutions, alternatives, preferences, and choices, the three process deficiencies described above should be mitigated.

Ultimately, it would still be the Company's plan to propose and some disagreements would still require resolution through a litigated proceeding. But a clear directive from the Commission concerning this working group and the collaborative expectation could significantly improve this process and ultimately improve the litigated proceeding. I suspect that the level of agreement entering such a proceeding after an extended joint plan development process would still be significantly greater than it has been historically. I also suspect that a narrowing of contested issues before litigation begins would make such a proceeding easier to administer, which is a goal all parties likely share.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

Attachment PJA-1

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

Wired Group, PO Box 620756, Littleton, CO 80162. palvarez@wiredgroup.net 303-997-0317

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modemization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

Appearances and Research Projects in Regulatory Proceedings

Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters. Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel testimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State. Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators.* Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us.* Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators.* St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

Attachment PJA-2

Virginia Electric and Power Company
Case No. PUR-2021-00127
Appalachian Voices
Second Set

As it pertains to the CIP, the following response to Question No. 61 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Heather Jennings
Director, Customer Information Platform
Dominion Energy Virginia

As it pertains to fixed assets, the following response to Question No. 61 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

David Williams
Supervisor, Fixed Asset Accounting
Dominion Energy, Inc.

Question No. 61

Request 2-61. Refer to Direct Testimony of Heather M. Jennings, page 5, which states, regarding the consideration of alternatives to the CIP, "Prior to Phase I, the Company considered continuing to build silos and patchworks of applications, and engaging in manual processes to perform certain functions within the legacy CIS. This would require the Company to replace the mainframe system that supports the CIS."

(a) Identify the primary vendors of the legacy CIS, including the software developer, software name and version, and "mainframe system that supports the CIS". Explain why the mainframe system that supports the CIS would have required replacement, as well as the reasons why the mainframe system need not be replaced for the CIP.

(b) Identify the primary vendors selected for the CIP, including software developer, software name and version, hardware platforms/suppliers, system integration/implementation consultants, etc.

(c) Provide the requests for proposals (RFPs) the Company issued for any aspect of the CIP project, including lists of all vendors who responded to each RFP. For each RFP the Company issued, provide the template used to evaluate vendor responses.

(d) Provide a diagram of the CIP ecosystem, depicting the systems which will supply data to the CIP, the systems which will use data from the CIP, the software and hardware platforms on which those systems reside, etc.

(e) Provide a list of all CIS hardware and software assets which will be retired when replaced by the CIP. Provide the book value, net of depreciation, of these assets as of December 31, 2020.

(f) Refer to the Company's response to subpart (e). Describe how the Company is removing the book value of each asset from its rate base as retired to make way for the CIP. If the Company is not removing the book value from rate base as these assets are retired, please explain why not.

(g) Provide the capital and O&M cost of the CIP incurred by year from 2018 through 2021.

(h) Provide an estimate of the nominal revenue requirement of the CIP by year from the response to subpart (d) provided over the life of the CIP. Include the calculation details in your response, as well as the calculations to convert the nominal revenue requirement of the CIP into present value.

(i) Provide any analyses the Company completed comparing the cost of acquiring the CIP as a capital asset to the cost of leasing a hosted CIP in a cloud-based, software-as-a-service model. If the Company completed no such analyses, please explain why not.

Response:

(a) The legacy CIS, referred to as "CBMS" at the Company, was developed and marketed as Customer/1 by Andersen Consulting.

CBMS currently operates on an older server that is not compatible with more modern applications. The older server would require replacement to continue to be supported by the vendor and the internal staff. Additionally, CBMS is not compatible with more modern server technology and cannot just be moved to another server. The CIP will operate on modern server technology that will replace the current mainframe system. See also the pre-filed direct testimony of Company Witness Jennings starting on page 4.

(b) Please refer to vendor agreements provided in Filing Schedule 46E to the Company's Petition.

(c) Please see Attachments APV Set 02-61(c)(1) and (2) (HMJ) ES for the RFP and results conducted in 2019.

Attachments APV Set 02-61(c)(1) and (2) contains extraordinarily sensitive information (RFP & RFI Results) in their entirety, and is being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Contracts and Prices Information and RFP & RFI Results dated July 19, 2021, any subsequent protective order or ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and the Agreements to Adhere executed pursuant to any such orders or rulings.

(d) See Attachment APV Set 02-61(c)(1) (HMJ) ES, specifically the files named Attachment B and Attachment L.

(e) The CIP will replace twelve current systems that support different aspects of the customer experience, as summarized in the table below.

Application	Brief Description	Customer or Employee Facing	In-Service Date
Customer Information System - CBMS (Customer Business Management System)	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	Employee	1996
Manage Account	Customer web self-service platform for residential & small commercial customers	Customer	2003
Key Customer	Self-service system for large customers that are assigned an account representative; used by the customer and the account representative. Has many similarities to Manage Account	Customer	2006
Property Manager Portal	Web self-service tool for property management companies to manage landlord agreements and turn on/turn off service for their properties	Customer	2013
AWA (Agency Web Access)	Web self-service application for charities & third-party agencies (e.g., Salvation Army) to make energy assistance payments on behalf of customers	Customer	2006
MDMS (Meter Data Management System)	System that processes and stores interval data used for billing; calculates billable consumption for interval meter data	Employee	2009
Gateway	Web-based front end to CBMS and other systems used in contact center; primary tool for customer service representatives to interact with customers.	Employee	2013

[illegible]	Brief Description	Customer/Employee Facing	In-Service Date
Knowledge	Allows for systematically capturing, describing, organizing, and sharing information including alerts, work processes, and policies across customer service	Employee	2016
E-Gain	Imports and sorts emails and work tickets creating queue; includes auto replies and templates for responses	Employee	2010
LanBill	Allows back office personnel to manually edit and print bills flagged for special handling; used to process large complex bills that are not fully automated in CBMS	Employee	1996
Bill Image	Renders an image of the bill on demand in Manage Account and Gateway	Employee	2003
Agiloft	Record keeping system used to track elevated customer issues and inquiries.	Employee	2011

See Attachment APV Set 02-61(e) (DW) for the net book of these assets as of December 31, 2020.

(f) As assets listed in part (e) are retired, the property, plant, and equipment. and associated accumulated depreciation of those retired assets will be removed and the corresponding gain or loss is recorded to the income statement. When the asset is retired, it is removed from rate base and the new CIP asset would be included once placed in service.

(g) Please refer to the "WP_CIP" tab of Attachment Staff Set 01-24(1) (ALT). There were no CIP costs incurred in 2018.

(h) Please refer to Filing Schedule 461, Statement 2, specifically the workpapers for CIP.

(i) The Company did not complete such an analysis. The Company reviewed industry best practices for utilities of a similar size, as well as what is commercially available. The CIP will utilize a combination of software as a service and traditional perpetual software licensing.

Virginia Electric and Power Company
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Appalachian Voices
Second Set

As it pertains to resilience and reliability, the following response to Question No. 35 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Bradley R. Carroll, Sr
Director of IT Telecommunications
Dominion Energy Virginia

As it pertains to security, the following response to Question No. 35 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Jonathan Bransky
Director Threat Intelligence
Dominion Energy Services

As it pertains to legal matters, the following response to Question No. 35 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Sarah R. Bennett
McGuireWoods LLP

Question No. 35

Refer to Direct Testimony of Bradley R. Carroll, Sr., page 7 at line 7 which states "The continuation of the Tier 2 network deployment in Phase 11 will enhance grid security, reliability, and resiliency." Refer also to the summary of Mr. Carroll's testimony summary, which states "Company-owned telecommunications (networks) is more secure, resilient, and reliable than leased carrier operations."

(a) Provide data regarding the security of MPLS facilities Dominion leases.
(b) Provide data regarding the security of MPLS facilities Dominion owns.
(c) Provide data regarding the resilience of MPLS facilities Dominion leases.
(d) Provide data regarding the resilience of MPLS facilities Dominion owns.
(e) Provide data regarding the reliability of MPLS facilities Dominion leases.
(f) Provide data regarding the reliability of MPLS facilities Dominion owns.
(g) Given the data provided in subparts (a) through (f), explain the basis for Dominion's belief that Company-owned telecommunications are more secure, resilient, and reliable than leased carrier options. If the data provided in response to subparts (a) through (f)

indicates Company-owned telecommunications are more secure, resilient, and reliable than leased carrier operations, provide any analysis which indicates that the level of improvement represented are worth the incremental cost to customers.

Response:

(a) and (b) The Company objects to this request as not relevant or reasonably calculated to lead to the discovery of admissible evidence in this proceeding. This non-public information is highly sensitive, the disclosure of which could threaten the security of the Company's system.

(c), (d), (e), (f) During the time period from January 1, 2020 to present, the Company has incurred 7 outages related to Company-owned telecommunication circuits. During the same time period, the Company has incurred 742 outages on telecommunication circuits leased from third parties.

(g) From a resilience and reliability perspective, there is a lack of alignment between public carrier goals and the Company's goals to run its operations with exceptionally high availability. Even the highly-regarded AT&T FirstNet network for first responders lacks sufficient resiliency needed to operate critical infrastructure, as evidenced in the December 2020 bombing in Nashville that took down a number of AT&T services including FirstNet. There are important criteria that need to be met when designing high availability networks including consideration for backup power, resilient core, and transport network designs with no single points of failure. Public carrier networks are optimized to provide return on investment whereas networks designed to utility-grade standards are optimized for availability.

As to security, the Company-owned network provides physical separation of network communication from public access. Public carriers may run multiple customer MPLS networks logically segmented on the same hardware. While the Company implements encryption where technically feasible to mitigate risks on non-Company owned circuits, the operator and anyone with access to the carrier's network can potentially read packets in the MPLS network. Depending on the carrier's MPLS architecture, there are potential risks that the carrier may misconfigure the MPLS network and cause network packets to pass through a public route, so it is not an absolute assurance that the Company traffic will remain secure on the carrier's network.

<u>Virginia Electric and Power Company</u>
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<u>Appalachian Voices</u>
<u>Second Set</u>

The following response to Question No. 37 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Bradley R. Carroll, Sr
Director of IT Telecommunications
Dominion Energy Virginia

As it pertains to rural broadband, the following response to Question No. 37 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

David Walker
Director of Rural Broadband
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 37 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Sarah R. Bennett
McGuireWoods, LLP

Question No. 37

Refer to Direct Testimony of Bradley R. Carroll, Sr., page 7 at line 14, which states "The Company can leverage the fiber laid in connection with its Tier 2 network to support the Commonwealth's initiatives to bring broadband to rural communities in Virginia. Specifically, the Company can lay enough fiber to serve its telecommunications needs at key facilities, and include additional fiber for lease to internet service providers—covering the "middle mile"—to improve availability of broadband for commercial, government, institutional and residential customers in Virginia. The telecommunications infrastructure completed in Phase 1 has enabled the Company's rural broadband pilot projects in Surry County, Botetourt County, and the Northern Neck Region of Virginia . . . "

(a) Provide data or analysis that the areas to which the Company proposes to lay fiber, including rural areas, are short of middle mile capacity and/or do not currently have broadband service. If the Company does not have such analysis, explain why not.

(b) Provide data or analysis that the rural broadband pilot projects in Surry County, Botetourt County, and the Northern Neck Region have been successful. If the Company does not have such analysis, explain why not.

(c) Has the Company received any interest from internet service providers in Virginia regarding leasing the Company's fiber. If so, please provide documentation of such interest.

Response:

(a) The Company objects to this request to the extent that it would require original work. Notwithstanding and subject to this objection, the Company provides the following response:

At this time, the Company has not overlaid the proposed Company fiber routes for Phase II with unserved areas in Virginia to quantify how much potential there exist for leveraging GT Plan fiber for rural broadband purposes. The Company did not do this analysis because providing rural broadband to unserved rural areas is not the primary driver of Phase II telecom. The primary objective of the GT Plan telecom project is to serve communications needs at key Company facilities. Enabling rural broadband is an added benefit or beneficial byproduct in areas where the GT Plan telecom project overlaps with areas in need of middle mile fiber to support the expansion of rural broadband.

(b) The construction of this projects is still in progress. Pursuant to Ordering Paragraph (3) of the Commission's March 25, 2021 Order Approving Broadband Pilot Projects in Case No. PUR-2020-00125, the Company will provide an annual progress report on these projects in March of 2022.

(c) The Company objects to this request as not relevant or reasonably calculated to lead to the discovery of admissible evidence in this proceeding, as leveraging Tier 2 telecom for rural broadband is not the primary driver of this project. Notwithstanding and subject to this objection, the Company provides the following response:

Yes, the Company has received interest from internet service providers ("ISPs"). The Company is engaged in ongoing discussions and negotiations with ISPs, which are at various stages of development.

Virginia Electric and Power Company
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Second Set

The following response to Question No. 23 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Robert Wright
Director, Grid Planning & Asset Management
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 23 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Sarah R. Bennett
McGuireWoods LLP

Question No. 23

Refer to Direct Testimony of Robert S. Wright, Jr., page 35 at line 8, which states "Because the actual customer voltage information from AMI is needed to determine the degree of voltage management that is possible, the Company is proposing to target a 2 volt reduction in delivered voltage initially, which would lower energy consumption approximately 1.0% on average for customers."

a) Confirm that line sensors could be used to secure voltage information for voltage optimization in lieu of AMI.
b) Confirm that the Company assumed a 2 volt reduction (or 2% voltage reduction?) and a 1% conservation rate for its benefit estimate of 651,000 MWh annually from Phase II voltage optimization (ALT Schedule 2, Table 33). If this cannot be confirmed, please provide the actual assumptions used to calculate this estimate.
c) Estimate the average voltage at which energy was delivered to customers over Dominion's distribution grid in 2020.
d) Provide the average head-end voltage for Dominion distribution circuits in 2020.
e) Describe in full the EM&V protocol Dominion will propose for the voltage optimization energy efficiency program referenced at RSW page 35 line 13.

Response:

a) The Company does not confirm this statement. The Company does not consider line sensors to be an alternative to smart meters for obtaining the customer voltage information that is necessary to ensure customers continue receiving acceptable voltage once voltage optimization is implemented. Additionally, premise level voltage data obtained from smart meters is needed to identify the upgrade projects necessary to enable voltage optimization.

b) Confirmed. The Company assumed a 2 volt reduction resulting in a 1% energy savings on average when estimating customer benefits.

c) The Company is not able to estimate the average voltage being delivered to customers without premises level data. The Company designs the distribution grid to deliver voltage within the targeted bandwidth of 114V to 126V during normal grid operations and responds to investigate and address voltage issues when reported by customers. A full deployment of smart meters would provide important information in support of such a system average. Many factors such as grid design, location on the distribution feeder, amount of customer load, number of customers connected to a service transformer, and voltage control settings affect the voltage being delivered to each customer.

d) Voltage control devices such as transformer load tap changers and circuit voltage regulators have specific settings calculated based on factors on a specific substation transformer or feeder such as the peak load expected and targeted customer voltage range. A typical baseline voltage setting is 123V.

e) The Company objects to this request as not relevant or reasonably likely to lead to the production of admissible evidence in this proceeding. The Company intends to include an EM&V plan for a voltage optimization energy efficiency program as part of its next DSM filing in December 2021.

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Case No. PUR-2021-00127
Appalachian Voices
Second Set

The following response to Question No. 7 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Robert Wright
Director, Grid Planning & Asset Management
Dominion Energy Virginia

Question No. 7

Refer to Plan page 25 and the reference to a "0.5% voltage optimization capability".

a) Confirm that Dominion expects to be able to reduce average feeder voltage by 0.5% through this program. If this cannot be confirmed, please explain, and provide the voltage benefit Dominion does expect from this program.
b) Confirm that Dominion used the voltage reduction estimate provided in response to subpart (a) to estimate the benefits of the program at 651,000 MWh avoided energy use annually (ALT Schedule 2, Table 33, page 31). If this cannot be confirmed, please explain, and provide the voltage reduction assumption Dominion used in the calculation of the 651,000 MWh avoided estimate.
c) Provide the conservation voltage factor Dominion assumed when translating the response to subpart (a) into the energy savings referred to in subpart (b).

Response:

The Company corrected the GT Plan Document on August 17, 2021, which included the correction that the Company anticipates completing infrastructure improvement that support implementing a 1.0% voltage optimization capability. This is consistent with the number listed on page 35 of Company Witness Wright's testimony as originally filed.

a) The Company expects to be able to reduce average feeder voltage by 2 volts through the voltage optimization enablement.
b) The Company used the 2 volt reduction to estimate the benefits of the project.
c) The assumed conservation voltage reduction factor is 0.6. This yields a 1.0% reduction in energy for a 1.67% reduction in voltage (2 volts on a 120-volt base).

Virginia Electric and Power Company
Case No. PUR-2021-00127
Appalachian Voices
Second Set

The following response to Question No. 44 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Robin Dail Massanopoli
Manager, Metering Solutions
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 44 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Sarah R. Bennett
McGuireWoods LLP

Question No. 44

Refer to Direct Testimony of Andrew L. Trump, Schedule 2, page 2, which indicates that reductions in "found on" truck rolls will deliver $1.2 million annually in steady-state savings.

a. Provide the headcount of "troublemen" employed by the Company in 2020.

b. Provide the reductions in troublemen and other field positions and or equipment to which the Company is willing to commit to secure this benefit.

Response:

a. Assuming the term "troublemen" refers to the Company's operations field personnel, in 2020, the Company employed 172 Electric Serviceman/1st Class; 34 Serviceman II; and 35 Service Helpers.

b. The Company objects to this request because the phrase "to which the Company is willing to commit to secure this benefit" is vague and undefined. The Company is committed to achieving all possible benefits associated with its proposed GT Plan investments while continuing to reliably operate its system. The Company will track the metrics identified in Company Witness Woomer's Schedule 2, and will report on those metrics in its annual reports. Notwithstanding and subject to this objection, the Company provides the following response:

For underlying assumptions and calculations for each AMI related benefit, please refer to the "AMI-Benefit" tab of Attachment Staff Set 01-24(2) (ALT) ES.

Virginia Electric and Power Company
Case No. PUR-2021-00127
Appalachian Voices
Second Set

The following response to Question No. 45(b) and (c) of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Robin Dail Massanopoli
Manager, Metering Solutions
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 45(b) and (c) of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Sarah R. Bennett
McGuireWoods LLP

Question No. 45(b) and (c)

Refer to Direct Testimony of Andrew L. Trump, Schedule 2, page 2, which indicates that reductions in customer calls will deliver $1.5 million annually in steady-state savings. . . .

b. Provide the headcount of personnel employed in the Company's call center functions in 2020.

c. Provide the reductions in call center headcount to which the Company is willing to commit to secure this benefit.

Response:

(b) In 2020, call center personnel were comprised of 109 employees and 225 contractors.

(c) The Company objects to this request because the phrase "to which the Company is willing to commit to secure this benefit" is vague and undefined. The Company is committed to achieving all possible benefits associated with its proposed GT Plan investments while continuing to reliably operate its system. The Company will track the metrics identified in Company Witness Woomer's Schedule 2, and will report on those metrics in its annual reports. Notwithstanding and subject to this objection, the Company provides the following response:
For underlying assumptions and calculations for each AMI related benefit, please refer to the "AMI-Benefit" tab of Attachment Staff Set 01-24(2)(ALT)ES.

Virginia Electric and Power Company
Case No. PUR-2021-00127
Appalachian Voices
Second Set

The following response to Question No. 46 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Robin Dail Massanopoli
Manager, Metering Solutions
Dominion Energy Virginia

Question No. 46

Refer to Direct Testimony of Andrew L. Trump, Schedule 2, page 2, which indicates that reductions in truck rolls for net metering conversions and vector analysis (voltage issues) will deliver $900,000 annually in steady-state savings. Provide the headcount and equipment reductions in distribution field service centers to which the Company is willing to commit to secure this benefit.

Response:

Not all AMI related benefits directly correspond to headcount and/or equipment reductions. For underlying assumptions and calculations for each AMI-related benefit, please refer to the "AMI-Benefit" tab of Attachment Staff Set 01-24(2) (ALT) ES.

Virginia Electric and Power Company
Case No. PUR-2021-00127
Appalachian Voices
Second Set

The following response to Question No. 51(a), (b), (e), (f) and (g) of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Robert Wright
Director, Grid Planning & Asset Management
Dominion Energy Virginia

Question No. 51(a), (b), (e), (f), and (g)

Refer to Direct Testimony of Andrew L. Trump, Schedule 2, Table 30 on page 27.

a) Table 30 indicates labor savings due to EAMS of $5.8 million annually. Provide the 2020 headcount for the Company's asset management function, as well as the labor and benefits spending for this amount of headcount in 2020.
b) Table 30 indicates labor savings due to EAMS of $5.8 million annually. Provide the headcount reductions in the asset management function to which the Company is willing to commit to secure this benefit.
e) Table 30 indicates economic benefits to customers from EAMS-related reliability improvements of $24.8 million annually. Environmental Respondent understands that the Company's position is that these reliability improvements will not come from EAMS itself, but from the prospective replacement of equipment the EAMS will identify as appropriate for such prospective replacement. Please confirm that Environmental Respondent's understanding is correct. If Environmental Respondent's understanding is not correct, please explain how the EAMS itself will deliver reliability improvements.
f) Refer to the Company's response to subpart (e). If Environmental Respondent's understanding as described is correct, please identify where in the Company's Plan the cost of prospective equipment replacement is incorporated, and quantify the capital investments due to prospective equipment replacement by year throughout the applicable cost-benefit analysis period. If the cost of prospective equipment replacement is not incorporated in the Plan, please explain why the Company's business case includes benefits for costs not incorporated in the Plan.
g) Environmental Respondent understands that Dominion intends to use EAMS and models based on EAMS data to identify equipment for prospective replacement. Environmental Respondent also understands that Dominion, like all utilities, employs periodic testing for many of the assets (power transformers, circuit breakers, relays, and wood poles) Dominion is likely to seek to replace through EAMS-based modeling. Provide any research, studies, analysis, or other documentation of which Dominion is aware which indicates the cost of prospective replacement through modeling delivers superior financial results for customers

over the standard practice of periodic testing of power transformers, circuit breakers, relays, and wood poles.

Response:

a) Currently, Company asset management activities are embedded in different operational groups throughout the distribution organization.
b) The Company objects to this request because the phrase "to which the Company is willing to commit to secure this benefit" is vague and undefined. The Company is committed to achieving all possible benefits associated with its proposed GT Plan investments while continuing to reliably operate its system. The Company will track the metrics identified in Company Witness Woomer's Schedule 2, and will report on those metrics in its annual reports. The Company also objects to this request because the term "asset management function" is vague and undefined. Notwithstanding and subject to this objection, the Company provides the following response: See the Company's response to Staff Set 01-24 for information on how these savings were calculated.
e) Appalachian Voices's understanding is partially correct. In addition to reliability benefits achieved with EAMS driving proactive equipment replacements, EAMS will also drive decisions related to equipment specifications, suppliers, warranty terms, and inspection and maintenance cycles that will also directly produce reliability benefits. See the Company's response to Staff Set 05-113.
f) The savings attributed to EAMS reliability benefits are intended to represent the net savings associated with proactive versus reactive work. Planned work, such as proactive equipment replacements driven by EAMS, is less costly than reactive replacements that also require restoration activities and the possibility of additional costs associated with variables such as overtime work and expedited equipment procurement.
g) The Company did not assess proactive replacements compared to current inspection and maintenance activities.

Virginia Electric and Power Company
Case No. PUR-2021-00127
Appalachian Voices
Second Set

The following response to Question No. 57 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices and received on August 20, 2021 has been prepared under my supervision.

Robert Wright
Director, Grid Planning & Asset Management
Dominion Energy Virginia

Question No. 57

Refer to Direct Testimony of Andrew L. Trump, Schedule 2, Table 18 on page 19, which indicates $1.3 million in annual steady state O&M savings from outage reductions. Provide the field service center headcount and equipment reductions to which the Company is willing to commit so secure this benefit.

Response:

The Company objects to this request because the phrase "to which the Company is willing to commit to secure this benefit" is vague and undefined. The Company is committed to achieving all possible benefits associated with its proposed GT Plan investments while continuing to reliably operate its system. The Company will track the metrics identified in Company Witness Woomer's Schedule 2, and will report on those metrics in its annual reports. Notwithstanding and subject to this objection, the Company provides the following response:

See the Company's response to Staff Set 01-24.

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

The following response to Question No. 28 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.

Andrew L. Trump
Senior Principal – Energy and Utilities
West Monroe Partners, LLC

Question No. 28

Refer to the direct testimony of Andrew Trump, p. 39, line 9. Please provide screenshots showing the input/output of the three ICE Calculator runs.

Response:

See Attachment Staff Set 01-28 (ALT). Screenshots of ICE Calculator outputs, along with Excel-based data downloads, can be located in tabs to the right of "ICE Outputs." ICE Calculator inputs in Excel form, along with detailed instructions for entering inputs into the ICE Calculator, can be found in tabs to the right of "ICE Inputs."

Layer 3) MFH, IGD, EAMS

ICE Calculator Inputs

Step 1

State: Virginia

Step 2

# Residential Customers	2,256,190
# Non-Residential Customers	207,064

Note: DEV customer counts are specific to the Virginia territory. While SAIDI And SAIDI metrics are measured at the system level, the ICE Calculation includes only the 2.4M DEV customers

Step 3

Initial Year of Improvement	2019
Expected Lifetime of Improvement	40
Expected Annual Inflation Rate	2%
Discount Rate (%)	6.8059645

Step 4 - Layer 1

	SAIFI	SAIDI
Without Improvement (baseline - 2019)	1.228	138.3
With Improvement (after 2029)	0.967	107.863

Step 5 - *Enter projected reliability metrics according to table below*

Note: Values for years 2034-2058 are same as those in 2033

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
SAIDI	138.3	138.3	137.1	135.8	131.8	127.4	121.1	117.1	113.6	110.2	107.9
CAIDI - Automatically Calculated	112.64	112.64	112.32	112.09	111.53	110.63	110.86	111.34	111.69	111.54	111.52
SAIFI	1.228	1.228	1.221	1.211	1.182	1.151	1.093	1.052	1.017	0.988	0.967

Step 6 - *Based upon the Non-Residential Customer count provided in Step 2, the ICE Calculator automatically produces a default split between Small C&I and Medium/Large C&I customers*

	DOE ICE Default Split
Small C&I	186,715
Medium/Large C&I	20,349

Note:

1) The DOE ICE calculator defines Small C&I as "Annual Energy Consumption of 50,000 kWh or less" and Medium/Large C&I as "Annual Energy Consumption of over 50,000 kWh"

2) Based on this definition, DEV's approximate count of Small C&I customers = 157,369, Medium/Large C&I customers = 49,695

3) The DOE ICE calculator default C&I customer split was used to be conservative

Step 7 - *The ICE calculator allows the user to overwrite default customer counts to account for redundant feeds--among other utility-specific requirements for conducting the analysis*

	Overwrite # of C&I Customers to eliminate customers with Redundant Feeds
Small C&I	186,715
Medium/Large C&I	20,345

Note: In a detailed review of C&I customers on the affected feeders, only 4 were found to have redundant feeds

Step 8 - Download ICE Calculator output (*link to tab*)

CERTIFICATE OF SERVICE

I hereby certify that the following have been served with a true and accurate copy of the foregoing via electronic service:

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