Case No. PUR-2019-00154
Sponsor: STAFF

Exhibit No. 23

Witness: VOLKMANN
Bailiff: RENEE MILES

PREFILED TESTIMONY

OF

CURT VOLKMANN

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUR-2019-00154

DECEMBER 20, 2019

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Summary of Curt Volkmann

Staff witness Volkmann identifies the following concerns with DEV's Cost Benefit Analysis ("CBA") for its proposed Grid Transformation ("GT") Plan:

1. Reliability benefits derived from the Interruption Cost Estimate ("ICE") Calculator, which represent two-thirds (66%) of the alleged benefits of the GT Plan, reflect the economic value of avoided outages, which cannot be measured or verified;
2. Reliability benefits derived from the ICE Calculator are overstated because they do not include the customer costs of momentary interruptions;
3. Reliability benefits attributed to commercial and industrial ("C&I") customers make up 95% of the overall improved reliability benefits alleged by the Company and appear to be overstated;
4. The GT Plan and CBA do not include any explicit analysis of cost contingencies or a corresponding range of potential benefit/cost ratios if costs are higher or lower than planned;
5. The GT Plan and CBA contain no sensitivity analyses of key assumptions or associated ranges of potential benefit/cost ratios; and
6. Certain identified benefit categories and assumptions are not credible.

Adjusting the Company's CBA to reflect these and other deficiencies results in the following:

Adjustments to Cost/Benefit Analysis	Benefits	Costs	Cumulative Net Benefit (Cost)	Cumulative Benefit/Cost Ratio
9/30/19 Hulsebosch Testimony	$3,026.1	$2,703.6	$322.5	1.12
10/25/19 Errata	$2,972.3	$2,703.6	$268.7	1.10
Correcting net present value formulas	$2,975.0	$2,909.7	$65.3	1.02
Including impact of momentary interruptions	$2,531.0	$2,909.7	($378.7)	0.87
Excluding "Avoided Poor Health Transformer Replacements"	$2,360.0	~~$2,909.7~~	~~($549.7)~~	~~0.81~~
Excluding "Avoided AMR Meter Replacements"	$2,293.3	~~$2,909.7~~	~~($616.4)~~	~~0.79~~
Attribution of benefits to correct customer classes	?		?	?
		$2,688.7	($328.7)	0.88
		$2,688.7	($395.4)	0.85

Mr. Volkmann's testimony provides a review of certain major components of the GT Plan. Among other findings, Mr. Volkmann identifies that Phase IB mainfeeder hardening, at a lifetime revenue requirement of $120 million to improve reliability for 24,000 customers, results in a lifetime revenue requirement of $5,000 per customer improved. In addition, he describes key characteristics of good grid modernization plans and assesses the Company's GT Plan relative to those characteristics. He also discusses the Company's approach to Non-wires Alternatives and identifies opportunities for improvements. When appropriate, he provides certain recommendations for the Commission's consideration.

PREFILED TESTIMONY

OF

CURT VOLKMANN

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUR-2019-00154

DECEMBER 20, 2019

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Curt Volkmann and I am President and founder of New Energy Advisors, LLC. My business address is 132 Lake Vista Circle, Fontana, Wisconsin, 53125. I am submitting this testimony on behalf of the Staff of the Virginia State Corporation Commission ("Staff"). Exhibit 1 details my educational and professional experience.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides a review of the Grid Transformation Plan ("GT Plan") filed by Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("DEV" or "Company") on September 30, 2019.[1] I will describe my concerns with DEV's Cost/Benefit Analysis ("CBA"), as well as other concerns I have with the Company's GT Plan. I will also describe key characteristics of good grid modernization plans and provide an assessment of DEV's GT Plan relative to these characteristics. Finally, I will discuss DEV's approach to Non-wires Alternatives and will provide recommendations for future GT Plans. Staff witness Myers will make certain

[1] I am aware that this is the second GT Plan submitted by the Company for Commission approval and have reviewed the Commission's Final Order on the Company's initial application for approval of a GT Plan.

recommendations relative to the approval of individual Phase IB GT Plan components based on the analysis provided in my testimony.

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF DEV'S GT PLAN RELATIVE TO THE CHARACTERISTICS OF WELL-DEVELOPED GRID MODERNIZATION PLANS IN OTHER JURISDICTIONS.

A. See Table 1 below for my overall assessment of DEV's GT Plan compared to well-developed grid modernization plans in other jurisdictions.

Table 1 - Overall GT Plan Assessment

Characteristics of Good Grid Mod Plans	DEV's Plan	Comment
1) Measurable goals and objectives	◔	Goals not measurable
2) Credible CBA	◑	Detailed but flawed
3) Metrics linked to goals and CBA	◔	No linkage, baselines or targets
4) Support for Integrated Distribution Planning (IDP)	◑	New IDP capabilities enabled, too reliant on utility-owned DER and batteries
5) Stakeholder engagement throughout	◑	Need plan for stakeholder engagement during implementation
6) Increased transparency of distribution system data	◔	Other than hosting capacity analysis, no data sharing
7) Enablement of decarbonization	◑	Foundational investments support future enablement
8) All required expenditures	◕	All included, need explicit cost contigencies
9) Synergies between investments	◑	AMI mesh network for load forecasting and voltage optimization, not field area network
10) Based on demonstrated need	◔	No demonstrated need for such significant reliability improvement

● = fully included ○ = missing

I will further compare DEV's Plan to other well-developed grid modernization plans in Section III below.

Q. PLEASE IDENTIFY CONCERNS YOU HAVE WITH THE CBA INCLUDED IN DEV'S PROPOSED GT PLAN.

A. Based on my analysis of DEV's GT Plan CBA, I have the following concerns:

1. Reliability benefits derived from the Interruption Cost Estimate ("ICE") Calculator, which represent two-thirds (66%) of the alleged benefits of the GT Plan, reflect the economic value of avoided outages, which cannot be measured or verified;
2. Reliability benefits derived from the ICE Calculator are overstated because they do not include the customer costs of momentary interruptions;
3. Reliability benefits attributed to commercial and industrial ("C&I") customers make up 95% of the overall improved reliability benefits alleged by the Company and appear to be overstated;
4. The GT Plan and CBA do not include any explicit analysis of cost contingencies or a corresponding range of potential benefit/cost ratios if costs are higher or lower than planned;
5. The GT Plan and CBA contain no sensitivity analyses of key assumptions or associated ranges of potential benefit/cost ratios; and
6. Certain identified benefit categories and assumptions are not credible.

Q. WHAT DO YOU RECOMMEND FOR THE COMPANY'S FUTURE GT PLAN FILINGS?

A. I recommend that the Company, in future GT Plan filings:

1) Include clearly defined measurable goals and objectives for its proposed GT Plan.
2) In the CBA:
   a) Account for the impact of momentary interruptions in calculating the value of reliability improvement following the guidance provided by Lawrence Berkeley National Laboratory ("LBNL") and Nexant, Inc. ("Nexant");
   b) Exclude the benefit category of "Avoided Poor Health Transformer Replacement";

c) Use reasonable assumptions based on actual historical data for replacing automated meter reading ("AMR") meters;

d) Properly attribute reliability benefits to customer classes;

e) Explicitly and transparently include cost contingencies and provide a corresponding range of potential benefit/cost ratios; and

f) Conduct a sensitivity analysis on the CBA assumptions, and develop a plan for validating, monitoring, and reporting on the key assumptions.

3) Identify key metrics to monitor the progress of the GT Plan. These metrics should be linked to the overall GT Plan goals, key CBA costs and benefits, key CBA assumptions, and include baselines, targets, and a plan for ongoing performance reporting.

4) Expand its approach to Non-wires Alternatives ("NWA") by:

a) Conducting one or more NWA pilots using resources on the customer side of the meter, such as thermostats, batteries, pool pumps, water heaters, and/or PV systems;

b) Conducting one or more NWA pilots using distributed energy resources ("DER") financed with private capital; and

c) Developing and implementing a plan for including DER developers and other third-parties in its NWA planning and implementation processes.

5) Develop a plan for publicly sharing distribution system data beyond the proposed Hosting Capacity Analysis.

II. COST-BENEFIT ANALYSIS

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S GT PLAN CBA.

A. DEV hired the consulting firm West Monroe Partners ("Consultant") to develop its CBA, which is based on the full 10-year GT Plan. In the Company's CBA, the Consultant compares costs, as measured by the present value of revenue requirements, to the present value of benefits over the life of the assets. The results are a net benefit of $65.3 million and a benefit/cost ratio of 1.02 as shown below.[2]

Table 2

Cost/Benefit Summary (Revenue Requirement Basis)
(in Millions)

BENEFITS & COSTS	PV[1]
BENEFITS *(Asset Life)*:	
Customer	$2,975.0
Avoided/Deferred Capital	$375.8
O&M Savings	$268.4
Energy & Demand Savings	$237.5
Improved Reliability	$1,974.3
Reduction of Bad Debt & Energy Diversion	$118.9
COSTS *(Revenue Requirement)* :	$2,909.7
Total Net Benefit (Cost):	**$65.3**
Total Benefit/Cost Ratio:	**1.02**

[1]Present Value (PV) calculated using Weighted Average Cost of Capital (WACC) of 7.62%

As shown in Table 2, the Company and its Consultant attribute two-thirds (66%) of the customer benefits, or $1.974 billion, to the economic value of improved reliability. Notably, because the costs and benefits are nearly equal, any small change in the underlying CBA assumptions could result in changes to the CBA Benefit/Cost ratio to make it net positive or net negative. As I explain below, the Company's CBA is deficient in several ways, including a lack of explicit cost contingencies and a sensitivity analysis.

Q. ARE THESE THE SAME CBA VALUES THAT THE COMPANY PROVIDED IN ITS PETITION FILED ON SEPTEMBER 30, 2019?

[2] Attachment Staff Set 7-89 (TGH), tab 'CBA Summary – Hulsebosch'. Select responses to interrogatories referenced in my testimony are attached as Appendix B.

A. No, the values in Table 2 above reflect a subsequent errata filing on October 25, 2019.[3] In addition to the errata, the CBA Summary above incorporates a corrected net present value formula provided by the Company in response to a Staff interrogatory.[4]

GT Plan Benefits

Benefits from Improved Reliability

Q. PLEASE IDENTIFY CONCERNS YOU HAVE WITH THE COMPANY'S QUANTIFICATION OF BENEFITS RESULTING FROM IMPROVED RELIABILITY.

A. I have several concerns. First, it is not possible for DEV to measure the alleged benefits from improved reliability provided by the ICE Calculator. The Company can measure the actual reduction in outage duration and frequency from investments in its GT Plan, but it cannot measure the actual economic value of avoided outage costs for its customers.

Second, the validity of the ICE Calculator output is only as good as the validity of the input data. Staff has concerns that certain inputs the Company used were incomplete, as I discuss below. For example, the Company did not consider the impact to customers from momentary interruptions, which results in overstated benefits. This is particularly concerning given that the Company's CBA reflects that costs and benefits

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[3] As originally filed, the CBA showed $118.9 million in net benefits and a benefit/cost ratio of 1.1. Direct Testimony of Thomas G. Hulsebosch at 4.

[4] In response to another Staff interrogatory asking if the Company intends to submit another errata filing, DEV stated, "The Company does not plan to file an errata at this time, but plans to make appropriate updates to the CBA, including the net present value calculation, as part of its rebuttal testimony." Company response to Staff Interrogatory No. 9-112.

are largely equal. Staff witness Essah discusses additional concerns regarding the validity of the ICE Calculator input data.

Third, the Company largely attributes reliability benefits from the Company's GT Plan to commercial and industrial ("C&I") customers.[5] In the Company's CBA, I found examples of where DEV should have more appropriately attributed the value of avoided outage costs to residential customers, as I explain further below.

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING THE QUANTIFICATION OF IMPROVED RELIABILITY BENEFITS?

A. Given my concerns, I believe the results of the CBA should be viewed with some skepticism and the Commission should consider this in determining which components of the Phase IB of the GT Plan to approve in this proceeding. Further, in any CBA filed in future GT Plans, the Commission should direct the Company to:

a) Account for the impact of momentary interruptions in calculating the value of reliability improvement following the guidance provided by LBNL and Nexant; and

b) Appropriately attribute reliability benefits to customer classes.

Economic Value of Outage Costs

Q. CAN THE COMPANY DIRECTLY MEASURE THE ECONOMIC BENEFITS TO CUSTOMERS FROM AVOIDED OUTAGES?

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[5] In the ICE Calculator model used for the Company's CBA, $1.87 of the $1.97 billion (95%) of the benefits are attributed to C&I customers

A. No. As I previously mentioned, the economic benefits from improved reliability are not directly measurable. Instead, the Company uses the ICE Calculator to develop its estimates.

Q. PLEASE DESCRIBE THE ICE CALCULATOR.

A. The ICE Calculator is a Department of Energy online tool developed by LBNL and Nexant.[6] It was designed for utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements.

The ICE Calculator uses an econometric model that includes 34 different datasets from interruption cost estimation or willingness-to-pay surveys conducted by 10 different utilities across the country between 1989 and 2012.[7] LBNL and Nexant intend the ICE Calculator outputs to reflect the economic value of avoided outage costs for residential, small C&I, and medium/large C&I customers.

Q. DOES THE ICE CALCULATOR INCLUDE INTERRUPTION COST ESTIMATES FOR THE COMPANY'S VIRGINIA CUSTOMERS?

A. No. None of the utility interruption cost surveys included in the ICE Calculator were conducted by Virginia utilities.

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[6] https://icecalculator.com/home.

[7] https://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf, p. iv. Of the 10 utilities included in the dataset, three are located in the Southeast, two are located in the Midwest, two are located in the West, one is located in the Southwest, and two are located in the Northwest. No surveys by utilities in the Northeast are included in the ICE Calculator datasets.

Impact of Momentary Interruptions

Q. PLEASE IDENTIFY SOME OF THE VARIABLES USED IN THE ICE CALCULATOR.

A. There are several variables required as inputs to the ICE Calculator including: (1) the number of customers by classification; (2) historical or baseline reliability as measured by SAIDI, SAIFI and CAIDI;[8] and (3) the expected reliability improvement from the planned grid modernization program.

Q. WHAT CHANGES IN RELIABILITY DOES THE COMPANY PROJECT FROM THE 10-YEAR GT PLAN?

A. The Company assumes the following:

- A 29% improvement in SAIDI, from 127.0 minutes per customer in 2019 to 89.9 minutes per customer in 2029.
- A 45% improvement in SAIFI, from 1.19 interruptions per customer in 2019 to 0.65 interruptions per customer in 2029.
- A 30% degradation in CAIDI, worsening from 106.4 minutes per interruption in 2019 to 138.6 minutes per interruption in 2029.[9]

Q. WHAT ARE THE IMPLICATIONS OF THESE ASSUMPTIONS?

[8] SAIDI = System Average Interruption Duration Index measured in minutes per customer; SAIFI = System Average Interruption Frequency Index measured in interruptions per customer; CAIDI = Customer Average Interruption Duration Index measured in minutes per interruption. The mathematical relationship is CAIDI = SAIDI / SAIFI

[9] Attachment Staff Set 1-07(6)(TGH), tab "Baseline Reliability Metrics", rows 14-16 (voluminous spreadsheet not included in Appendix B).

A. The Company assumes that its proposed GT Plan will result in its customers experiencing fewer sustained outages and less total outage time, but when sustained outages do occur, they will last longer.[10]

Q. ARE THESE ESTIMATED RELIABILITY IMPROVEMENTS REASONABLE?

A. No. I understand how the Company calculated estimated improvements in SAIDI and SAIFI, but the Company has ignored the impact of increased momentary interruptions that its customers will experience from the proposed GT Plan investments.[11]

Q. HOW WILL THE COMPANY'S PROPOSED GT PLAN RESULT IN INCREASED MOMENTARY INTERRUPTIONS FOR CUSTOMERS?

A. The Company is proposing to deploy Fault Location, Isolation, and Service Restoration ("FLISR") grid technologies.[12] The FLISR technologies identify the location on the circuit where a fault has occurred, isolate the faulted line segment, and restore service to all customers not connected to the faulted line segment. As the Company explains, "an outage that would have caused 3,000 customers to lose power for approximately 2 hours would now have 2,500 customers experiencing a 'momentary outage' of less than two minutes, and the remaining 500 customers having a sustained outage of less than 2 hours ..."[13]

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[10] Company response to Staff Interrogatory No. 4-47.
[11] The Institute of Electrical and Electronics Engineers ("IEEE") defines a momentary interruption as those lasting less than five minutes. The Company defines momentary interruptions to be those lasting less than two minutes.
[12] The Company also refers to FLISR as Self-Healing Grid.
[13] Direct Testimony of Robert S. Wright, Jr., at 7:16-21

The Company is also proposing to install nearly 2,400 reclosers as part of its Mainfeeder Hardening program.[14] When these devices sense a fault, they temporarily interrupt power downstream from their location and then automatically reclose and restore power if the fault has cleared. Customers on circuits with these new reclosers could experience fewer sustained interruptions but an increase in momentary interruptions. DEV's omission of the economic impacts of momentary interruptions in its CBA could be significant, as I explain later in my testimony.

Q. DOES THE COMPANY TRACK AND REPORT MOMENTARY INTERRUPTIONS?

A. No. The industry standard for reporting this is the Momentary Average Interruption Frequency Index ("MAIFI"). In response to a Staff Interrogatory, the Company stated, "The Company does not track … MAIFI, as it does not have the necessary operational visibility of distribution grid devices …"[15]

Q. CAN CUSTOMERS INCUR ACTUAL COSTS FROM MOMENTARY INTERRUPTIONS?

A. Yes. Retail businesses may lose sales if customers leave when cash registers are unavailable due to lack of electricity. Manufacturing plants may incur significant costs because of lost production and idle workers while product assembly line controls are reset. Plants may have to scrap material and clean up messes caused when factory processes stop suddenly.[16] For example, I read about a bottling plant that experienced

[14] Attachment Staff Set 2-09(b)(1)(RCS), tab 'summary', cells D3:D12
[15] DEV's response to Staff Interrogatory No. 5-74
[16] https://www.power-grid.com/2015/06/12/utility-industry-targets-growing-concern-momentary-outages/#gref

a momentary outage. Immediately following the brief interruption, there was a loud crash as bottles fell from above. All of the bottles had fallen because they had been held up above the production line by vacuum technology, which requires a continuous supply of electricity. The costs from lost time, lost production, and lost materials from even a brief outage can be significant.[17]

Q. HAVE LBNL AND NEXANT ESTIMATED THE COSTS OF MOMENTARY INTERRUPTIONS?

A. Yes. LBNL and Nexant have quantified the costs of both sustained and momentary interruptions using the econometric model underlying the ICE Calculator. Their most recent analysis shows a momentary interruption cost per event of $12,952 for medium and large C&I customers.[18] Momentary interruptions do have real costs, and the Company should include these costs in its CBA.

Q. DO LBNL AND NEXANT RECOMMEND THE CONSIDERATION OF MOMENTARY INTERRUPTIONS WHEN USING THE ICE CALCULATOR?

A. Yes. On the ICE Calculator website's 'Documentation' tab, the first document listed is titled, "Using the ICE Calculator for FLISR Reliability Improvement Value (2018)". The description of the document states,

> [FLISR] is a popular way to improve service reliability ... The ICE Calculator is a widely accepted tool for calculating … the value of reliability improvements. ***It is very important to use the tool properly to avoid over-estimating the value.*** This document provides a very basic example of how to use the ICE tool to accurately calculate the

[17] https://www.energycentral.com/c/gr/momentary-outages-inconvenient-problem-millennials-won't-tolerate
[18] https://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf, p. 31.

> reliability benefits when sustained outages are changed to momentary outages.[19]

The referenced document states,

> Since the ICE calculator does not directly call out MAIFI, the user might be tempted to simply input new SAIDI, CAIDI and SAIDI numbers. However, ***this substantially overstates the reliability benefit because it assumes there will not be any momentary interruptions …*** Had this [correct model] not accounted for the momentary outages, … the ICE Calculator overstates the more accurate amount by … ***about 50% more benefit than will actually be realized.***[20]

Q. DID THE COMPANY INCLUDE THE IMPACT OF MOMENTARY INTERRUPTIONS WHEN USING THE ICE CALCULATOR FOR ITS CBA?

A. No. In response to Staff's Interrogatory, DEV indicated that it "did not quantify the number of momentary outages … or their impact, as this information has not been historically captured."[21]

Q. WHAT IS THE POTENTIAL IMPACT ON THE COMPANY'S CBA OF INCLUDING MOMENTARY INTERRUPTIONS IN THE ICE CALCULATOR?

A. As I explained above, the LBNL and Nexant guidance document indicates that ignoring momentary interruptions can result in a 50% overstatement of reliability benefits. Correcting a 50% overstatement of reliability benefits from FLISR and Mainfeeder Hardening would result in a CBA Net Benefit (Cost) decrease from $65.3 million to $(378.7) million and decrease in the Benefit/Cost Ratio from 1.02 to 0.87.[22]

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[19] https://icecalculator.com/documentation (emphasis added)

[20] https://icecalculator.com/assets/documents/Using_the_ICE_Calculator_for_FLISR_Reliability_Improvement_Value.pdf (emphasis added)

[21] Company response to Staff Interrogatory No. 5-76(b).

[22] Based on a reduction in CBA Reliability benefits from $1.974 billion to $1.530 billion.

Customer Class Attribution

Q. HOW SHOULD THE COMPANY ATTRIBUTE IMPROVED RELIABILITY BENEFITS DERIVED IN ITS CBA TO CUSTOMER CLASSES?

A. Generally, a C&I customer, who is not already self-insured with backup electric power generation, will experience higher economic losses during an outage compared to a residential customer. Accordingly, it is important that improved reliability benefits calculated in the CBA are attributed to the correct customer classes to accurately quantify those benefits.

Q. PLEASE PROVIDE EXAMPLES OF RELIABILITY BENEFITS THAT THE COMPANY HAS NOT CORRECTLY ATTRIBUTED TO THE APPROPRIATE CUSTOMER CLASS.

A. The Company claims that $184 million of improved reliability benefits will result from proactive upgrades of service transformers.[23] Of this amount, the Company attributes $174 million (95%) to large C&I customers, implying that the majority of proactive upgrades will be for service transformers serving large C&I customers. However, through discovery, Staff learned that the data supporting the costs for this category are from historical upgrades of residential service transformers, not large C&I.[24] Attributing 95% of these benefits to large C&I customers does not appear to reflect the customer class benefiting from the upgrade, resulting in a potential overstatement of the benefits in the CBA.

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[23] Attachment Staff Set 4-39(1)(TGH), Line 247, Column G.

[24] According to DEV's response to Staff Interrogatory No. 9-114, the Company's standard sizes for residential single-phase service transformers are 167 kVA and below. The data provided in Attachment Staff Set 9-113 (RCS), tab 'Material pivot,' show that 98% of the transformers used in the analysis are 167 kVA or smaller.

Another example is DEV's proposed Enterprise Asset Management System or EAMS, which the Company claims will allow it to "pro-actively identify and resolve asset performance issues by scheduling the maintenance and replacement of assets in a more efficient manner."[25] The Company estimates $136 million of improved reliability benefits from EAMS,[26] and attributes $122.9 million (90%) of this benefit category to large C&I customers. It does not seem reasonable that large C&I customers will receive 90% of the benefit from the EAMS capability. It seems more probable that all customer classes will benefit from this improved reliability. A more reasonable customer class attribution of these benefits could lead to a lower total benefit estimate.

Avoided/Deferred Capital

Q. HOW MUCH BENEFIT DID THE COMPANY CLAIM IN ITS CBA FROM AVOIDED/DEFERRED CAPITAL EXPENDITURES?

A. The Company identified $375.8 million of benefits attributable to Avoided/Deferred Capital.[27]

Q. DOES STAFF HAVE ANY CONCERNS WITH THE BENEFITS IN THIS CATEGORY?

A. Yes. For the reasons discussed below, Staff believes that the Company should exclude the "Avoided Poor Health Transformer Replacement" component, and that the Company has not supported the benefit of accelerated replacement of automated meter reading ("AMR") meters with reasonable assumptions based on historical data.

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[25] Company response to Staff Interrogatory No. 4-48(a).
[26] Attachment Staff Set 4-39(1)(TGH), Lines 257-261, Column G.
[27] Attachment Staff Set 4-39(1)(TGH), Line 10, Column G.

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING BENEFITS RESULTING FROM AVOIDING/DEFERRING CAPITAL EXPENDITURES?

A. I recommend that the Company:

a) Exclude the $171 million benefit category of "Avoided Poor Health Transformer Replacement";

b) Exclude the $67 million benefit category of "Avoided AMR Meter Replacement"; and

c) Use reasonable assumptions based on actual historical data for quantifying the benefit of future AMR meter replacement.

Q. PLEASE EXPLAIN THE BENEFIT CATEGORY OF "AVOIDED POOR HEALTH TRANSFORMER REPLACEMENT".

A. The Company proposes to spend $285 million over ten years to proactively replace poor health transformers,[28] claiming this will result in a benefit from avoided future transformer replacement costs. The Company explains, "This (benefit)... represents the avoided cost associated with future replacements of poor health transformers. This benefit is for deferred capital that will not have to be spent in the future because of the proactive replacement of these transformers as part of the GT Plan."[29] In other words, the Company is claiming that spending money to replace transformers sooner rather than later is a benefit. The Company assumes the exact same cost per transformer for a proactive replacement as it does for an avoided future replacement, so there are no net savings for customers. The Company should exclude the $171 million[30] of "Avoided Poor Health Transformer Replacement" benefits from its CBA.

[28] Attachment Staff Set 7-89 (TGH), tab 'WP_Proactive Upgrades', cell Y21.
[29] Company response to Staff Interrogatory No. 7-90.
[30] Attachment Staff Set 4-39(1)(TGH), Line 78, Column G.

Q. WHAT IS THE IMPACT ON THE CBA IF THE COMPANY EXCLUDES THE "AVOIDED POOR HEALTH TRANSFORMER REPLACEMENT" BENEFIT?

A. Excluding this component from the Company's CBA ~~reduces~~ increases the total Net Benefit (Cost) from $65.3 million to ~~$(105.8)~~ $115.2 million and the Benefit/Cost Ratio from 1.02 to ~~0.96~~ 1.04.[31] Combined with the inclusion of momentary interruption impacts in the ICE Calculator as I describe above, the cumulative Net Benefit (Cost) becomes ~~($549.7)~~ ($328.7) and the cumulative Benefit/Cost Ratio is ~~0.81~~ 0.88.

Q. DID THE COMPANY USE REASONABLE ASSUMPTIONS TO CALCULATE BENEFITS ASSOCIATED WITH AVOIDED AMR METER REPLACEMENTS?

A. No. The Company is claiming $67 million of benefits from this GT Plan component.[32] One of the Company's underlying assumptions for this benefit is an average annual 45% increase in AMR meter failures.[33] The table below shows the Company's historic number of AMR meters exchanged due to failed communications modules[34] (which it began tracking in 2016) and the Company's forecasted number of AMR meter failures in its CBA using the assumed 45% annual increase of failures.[35]

[31] ~~Based on a reduction in CBA reliability benefits from $1.974 billion to $1.803 billion.~~ Also excludes costs for proactive Poor Health Transformer replacement

[32] Attachment Staff Set 4-39(1)(TGH), Line 20, Column G.

[33] Attachment Staff Set 4-39(2)(TGH), cell C10

[34] Company response to Staff Interrogatory No. 7-94.

[35] Attachment Staff Set 4-39(1)(TGH), Line 21.

Table 3 - AMR Meter Failures

	Exchanges completed due to failed AMR communications modules	Forecasted AMR Meter Failures in CBA
2016	3,698	
2017	4,993	
2018	8,267	
2019		13,000
2020		50,845
2021		106,360
2022		187,510
2023		305,844
2024		478,107
2025		728,581
2026		254,170
Total	16,958	2,124,417

Based on the historic data above, it does not seem reasonable that, absent deployment of smart meters (also referred to as advanced metering infrastructure or "AMI"), the Company would have to replace over 2.1 million AMR meters over the next 8 years. Neither does it seem reasonable that the Company will experience a 45% annual increase in AMR meter failures.

Staff witness Essah further discusses projected AMR meter failures based on historical data.

Q. WHAT IS THE IMPACT ON THE CBA IF THE COMPANY EXCLUDES THE "AVOIDED AMR METER REPLACEMENT" BENEFIT?

A. Excluding this component from the Company's CBA reduces the total Net Benefit (Cost) from $65.3 million to $(1.5) million and the Benefit/Cost Ratio from 1.02 to

1.00.[36] Combined with the other CBA modifications I describe above, the cumulative Net Benefit (Cost) becomes ~~($616.4)~~ ($395.4) and the cumulative Benefit/Cost Ratio is ~~0.79.~~ 0.85

<u>GT Plan Costs</u>

Q. **PLEASE IDENTIFY THE COSTS INCLUDED IN THE COMPANY'S CBA RELATED TO THE GT PLAN.**

A. The CBA consists of the planned expenditure categories shown below.[37]

<u>Table 4 - GT Plan Expenditures</u>

Category	**Revenue Requirement Present Value (In Millions)**	**% of Total**
Grid Hardening	$986.4	33.9%
Telecommunications Infrastructure	$499.4	17.2%
Advanced Metering Infrastructure	$437.5	15.0%
Customer Information Platform	$341.3	11.7%
Grid Technologies	$409.2	14.1%
Cyber Security	$72.6	2.5%
Smart Charging Pilot Program	$34.8	1.2%
Transportation Electrification DSM Program	$19.8	0.7%
Physical Security	$51.0	1.8%
Time Varying Rates/Programs	$49.6	1.7%
Stakeholder and Customer Education	$8.2	0.3%
Total	**$2,909.8[38]**	**100.0%**

[36] Based on a reduction in CBA reliability benefits from $1.974 billion to $1.908 billion.
[37] Staff witness Myers Table 7, nominal dollars.
[38] The total lifetime revenue requirement on a PV basis of $2.91 billion includes the lifetime revenue requirement of time varying rates/programs ($49.6 million on a PV basis) and the transportation electrification demand-side management program ($19.8 million on a PV basis) because these items are included in the CBA, as presented by Company witness Hulsebosch. They are not, however, included in the GT Plan as proposed by the Company. As a result, the lifetime revenue requirement of the GT Plan presented in Staff witness Myers' Table 3 is $2.84 billion ($2.91 billion less the time-varying rates/program of $49.6 million and the transportation electrification of $19.8 million).

Table 4 reflects the asset lifetime revenue requirements from the total 10-year GT Plan. However, the Company is only seeking approval of the costs for Phase IB. As shown above, the largest cost component of the Company's 10-year GT Plan is for Grid Hardening, though a majority of those costs begin after Phase IB. I will explain my concerns with certain major GT Plan components below.

Review of Major Cost Components

Q. PLEASE IDENTIFY YOUR CONCERNS WITH GRID HARDENING.

A. Approximately 95% of the Company's proposed capital expenditures in the Grid Hardening category are for Mainfeeder Hardening and Proactive Transformer Upgrades. The Company is proposing to spend \$48 million[39] in Phase IB for Mainfeeder Hardening at a lifetime revenue requirement of \$120 million (in nominal dollars)[40] to improve reliability for 24,000 customers.[41] This equates to a lifetime revenue requirement of \$5,000 per customer. Over ten years, the Company proposes to spend \$668 million on Mainfeeder Hardening at a lifetime revenue requirement of \$1.67 billion (in nominal dollars)[42] to improve reliability for 491,000 customers. This equates to a lifetime revenue requirement of \$3,400 per customer. This is a very expensive approach to improve reliability for a subset of DEV's customers. As I previously explained, I am skeptical that the customer benefits from this improved reliability exceed the costs because of how the Company has applied the ICE Calculator.

[39] Direct Testimony of Robert S. Wright, Jr., Schedule 1, nominal dollars.
[40] Staff witness Myers Table 7, nominal dollars.
[41] Direct Testimony of Robert S. Wright, Jr., at 26.
[42] Staff witness Myers Table 7, nominal dollars.

Similarly, as discussed previously, I am skeptical that the Company's proposed capital expenditures of $48 million in Phase IB and $504 million over 10 years for Proactive Transformer Upgrades will result in customer benefits that exceed the costs.

Staff witness Essah raises significant concerns about how the Company has quantified the expected reliability improvements from Grid Hardening, a key input into the ICE calculator.

Q. PLEASE IDENTIFY YOUR CONCERNS WITH THE TELECOM CATEGORY.

A. The proposed Telecom expenditures include $183 million over ten years[43] to deploy a Field Area Network ("FAN") to communicate with field devices. The Company intends to utilize the FAN to enable the FLISR technologies I previously described. I am concerned that the FAN may be redundant with the Company's proposed AMI communications network.

Q. PLEASE IDENTIFY YOUR CONCERNS WITH AMI.

A. I am generally supportive of the Company's proposed deployment of AMI. However, I am concerned that the Company may be missing an opportunity to save costs by deploying a single communications network to serve both as the FAN and to enable AMI. I will later explain how Xcel Energy in Minnesota has accomplished this.

Q. PLEASE IDENTIFY YOUR CONCERNS WITH GRID TECHNOLOGIES.

[43] Attachment Staff Set 7-89 (TGH), tab 'WP_Telecom', Line 6, column G..

A. These categories include a variety of proposed software and hardware deployments.[44] I am most concerned about the Company's plans to spend $24 million in Phase IB and $375 million over ten years for a Self-Healing Grid or FLISR. Again, I believe the Company's use of the ICE Calculator fails to demonstrate that the customer benefits from improved reliability exceed the costs.

The Company is also proposing to spend $7.2 million in Phase IB for a Locks Campus Microgrid. The preliminary costs for this project **[Begin Confidential]** [redacted] **[End Confidential]**[45] and it is not clear to me what the Company intends to demonstrate that is unique from what other utilities have already proven with microgrids.

Finally, DEV includes in the Grid Technologies category its plan to develop and publish a Hosting Capacity Analysis ("HCA"). This is an important capability to help the Company and its customers understand where the distribution system can accommodate additional DER without the need for grid upgrades. Staff fully supports the Company's proposed development of an HCA.

Q. DO YOU HAVE CONCERNS ABOUT THE COMPANY'S PROPOSED CUSTOMER INFORMATION PLATFORM ("CIP")?

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[44] These categories include Self-Healing Grid or FLISR, Hosting Capacity Analysis, Distributed Energy Resource Management System or DERMS, Advanced Analytics, Voltage Optimization, Locks Campus Microgrid, Enterprise Asset Management System or EAMS, and Outage Management System or OMS.
[45] Filing Schedule Wright, Confidential Attachment B, p. 38.

A. No. As Staff witness Myers explains, the cost estimates for the CIP are detailed and well supported. The Company's legacy customer information system is at the end of its useful life and in need of replacement.

Q. DO YOU HAVE CONCERNS ABOUT THE COMPANY'S PROPOSED INVESTMENTS IN CYBER AND PHYSICAL SECURITY?

A. No.

Cost Contingencies

Q. DO YOU HAVE CONCERNS WITH THE FACT THAT DEV'S GT PLAN DOES NOT CONTAIN EXPLICIT COST CONTINGENCIES?

A. Yes. The Company should explicitly and transparently include cost contingencies in the GT Plan along with a corresponding range of potential benefit/cost ratios.

Q. PLEASE EXPLAIN WHAT COST CONTINENCIES ARE AND WHY THEY ARE IMPORTANT.

A. Cost contingencies are amounts added to base costs in a spending plan to account for risks and uncertainty. Cost contingencies effectively provide a range of expected costs and best- and worst-case benefit/cost ratios. As with all CBA assumptions and calculations, it is important that the Company's inclusion of cost contingencies be explicit and transparent.

Good project management practices call for the use of cost contingencies, particularly for such a large, complex project deploying new technologies over a 10-year period. Risks and uncertainties that could impact the GT Plan costs include, but are not limited to, unknowns related to the integration of new and legacy IT systems;

equipment deployment delays due to weather or other factors; emergence of new viable technologies; new security threats or vulnerabilities; and changing legislation or regulations.

Q. DOES DEV'S GT PLAN INCLUDE COST CONTINGENCIES?

A. Somewhat, but the Company has buried the cost contingencies in its CBA and they are not transparent. In response to a Staff interrogatory, the Company explains,

> There are no specific, separate line items identified for contingency for the various components of the GT Plan. Instead, contingency costs were applied to each of the components of the GT Plan to varying degrees based on the nature of the program and the proposed spend profile. This was considered in the bottoms-up development of costs and applied within the specific cost categories where it was deemed appropriate, such as labor costs and material costs. In general terms, contingency was applied to each area somewhere between 0% and 10%.[46]

I am concerned that the Company may not have included sufficient cost contingencies for a program as complex as the GT Plan. Because the contingencies are not explicit and transparent, I cannot determine the sufficiency of the contingencies included in the Company's GT Plan.

Sensitivity Analysis of Key Assumptions

Q. WHAT IS YOUR RECOMMENDATION REGARDING A SENSITIVITY ANALYSIS OF KEY ASSUMPTIONS IN THE COMPANY'S CBA?

A. For future GT Plan filings, the Commission should require the Company to conduct a sensitivity analysis on the assumptions in its CBA, and to develop a plan for validating,

[46] Company response to Staff Interrogatory No. 9-110.

monitoring, and reporting on the key assumptions that have the biggest impact on the benefits and costs of its GT Plan.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY A SENSITIVITY ANALYSIS.

A. The Company's GT Plan CBA is based on a wide range of assumptions such as future reliability improvements, future transformer and AMR meter failure rates, future customer participation in TOU programs, future EV adoption rates, etc. Most, if not all, of these assumptions are uncertain. A sensitivity analysis determines how much the overall costs or benefits change from a change in one or more key assumptions.

Q. DID THE COMPANY PERFORM A SENSITIVITY ANALYSIS ON ITS CBA IN THIS CASE?

A. No. In response to a Staff Interrogatory, the Company stated that "West Monroe was not tasked with creating modeling sensitivities for each of these alternatives, nor were detailed sensitivities completed for all inputs and assumptions that drive the modeling calculations."[47]

Q. WHY IS A SENSITIVITY ANALYSIS IMPORTANT?

A. A sensitivity analysis identifies the assumptions that have the most impact on the overall costs and benefits of the GT Plan, thus highlighting the key assumptions that the Company should further validate, monitor, and report on throughout the GT Plan implementation.

Q. CAN YOU PROVIDE AN EXAMPLE?

[47] Company response to Staff Interrogatory No. 9-111.

A. Yes. I previously mentioned that the Company assumed a 45% improvement in SAIFI from the GT Plan and that this is a key input into the ICE Calculator. What would the reliability benefits be if the GT Plan results in only a 35% improvement in SAIFI? What would the reliability benefits be if the GT Plan results in a 55% improvement in SAIFI? A sensitivity analysis would provide answers to these types of questions.

Staff witness Essah addresses the Company's computer model-based calculation of customer minutes of interruption compared to actual historical data. Dr. Essah's testimony on this issue underscores the need for a sensitivity analysis.

III. <u>DEV'S GT PLAN COMPARED TO OTHER GRID MOD PLANS</u>

Q. ARE YOU FAMILIAR WITH GRID MODERNIZATION PLANS IN OTHER JURISDICTIONS?

A. Yes. Over the last 18 months, I have served as a technical advisor or expert witness reviewing grid modernization and distribution investment plans in California, Minnesota, Iowa, Michigan, and Ohio. On behalf of GridLab,[48] I am also developing a Grid Modernization Playbook, which will include characteristics of good grid modernization plans based on my understanding of relevant activity in over 20 states.

Q. WHAT DO YOU CONSIDER TO BE THE CHARACTERISTICS OF WELL-DEVELOPED GRID MODERNIZATION PLANS?

[48] http://gridlab.org.

A. In my experience, the most effective plans have full transparency and clear accountability for delivery of promised customer benefits. I consider the characteristics of well-developed grid modernization plans to include:

1. Overall measurable goals and objectives;
2. A credible CBA to justify expenditures;
3. Metrics linked to goals and CBA components with baselines, targets, and ongoing reporting;
4. Support for new Integrated Distribution Planning ("IDP") capabilities;[49]
5. Stakeholder engagement during planning and implementation;
6. Increased transparency of distribution system data;
7. Enablement of de-carbonization and beneficial electrification;
8. Inclusion of all required expenditures, including those beyond the initial period of the request;
9. Synergies between investments; and
10. Investments based on a demonstrated need.

I will discuss each of these characteristics in more detail below.

Overall Measurable Goals and Objectives

Q. DOES DEV'S GT PLAN CONTAIN MEASURABLE GOALS AND OBJECTIVES?

A. No. The Company identifies the following goals for its GT Plan:

- **Optionality:** Enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access.

[49] IDP capabilities include improved load and DER forecasting, hosting capacity analyses, identification/publication of grid needs and locational value, explicit consideration of non-utility owned DER as NWA, and NWA acquisition.

- **Sustainability:** Evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles.

- **Resiliency:** Build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management.

- **Affordability:** Deliver value for customers by optimizing demand and seeking to reduce system and customer costs.[50]

These are more like guiding principles rather than measurable goals and objectives.

Q. CAN YOU PROVIDE AN EXAMPLE OF A GRID MODERNIZATION PLAN THAT INCLUDES OVERALL MEASURABLE GOALS AND OBJECTIVES?

A. Yes. In a 2012 order,[51] the Oregon Public Utility Commission ("OPUC") adopted policy goals and objectives, reporting requirements, elements of annual reports, and general OPUC guidelines for investing in smart-grid technologies. These goals and objectives are:

- Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network:
  - Improve fault detection, isolation, and restoration;
  - Reduce the frequency, scale, and duration of outages;
  - Increase resiliency to withstand physical and cyber-attacks, and natural disasters;
  - Provide real-time visibility into state of systems and assets;
  - Reduce power line losses;
  - Enhance the ability to provide reactive power, voltage support, and other ancillary services;
  - Increase the ability to control voltage and power flows;
  - Increase capacity utilization and upgrade capacity ratings on existing lines; and
  - Enable more precise sizing of equipment.

- Enhance the ability to save energy and reduce peak demand:
  - Enable integration and control of smart appliances and other smart consumer devices;

[50] Plan Document, p. 1.
[51] https://apps.puc.state.or.us/orders/2012ords/12-158.pdf.

    - Provide access to detailed, real-time information on electricity use and costs to help customers manage use and costs and understand how to save; and
    - Improve monitoring of building equipment to alert building owners to problems and improve performance and control of equipment and systems.
- Enhance customer service and lower cost of utility operation:
    - Reduce costs of meter reading;
    - Reduce costs and improve customer service through more efficient notification of and response to outages, more efficient detection of theft and broken meters, more effective handling of service orders, and improved billing, credit, collection, and connection/disconnection practices; and
    - Reduce billing errors and call center transactions.
- Enhance the ability to develop renewable resources and distributed generation:
    - Reduce the cost of integrating utility-scale wind and solar into the grid;
    - Improve the ability to safely and efficiently integrate distributed generation and energy storage into the power system;
    - Facilitate new resource options for capacity and ancillary services; and
    - Enable microgrids.

The OPUC requires each Oregon electric utility to file annual smart-grid reports including its own smart-grid strategy, goals and objectives; the status of smart-grid investments and progress toward goals and objectives; and progress on related activities (i.e., activities to address physical- and cyber-security, privacy, customer outreach and education, and IT and communication infrastructure).

A Credible Cost/Benefit Analysis to Justify Expenditures

Q. DOES DEV'S GT PLAN INCLUDE A CREDIBLE CBA?

A. While the Company's CBA is detailed, it has significant deficiencies as I previously described.

Q. CAN YOU PROVIDE AN EXAMPLE OF A GRID MODERNIZATION PLAN WITH A CREDIBLE CBA TO JUSTIFY EXPENDITURES?

A. Yes. Xcel Energy in Minnesota recently submitted its 2019 Integrated Distributed Plan and request for approval of its Advanced Grid Intelligence and Security ("AGIS") plan to the Minnesota Public Utilities Commission.[52] I am still reviewing the filing but am initially impressed by its CBA, which is conservative but realistic. The AGIS plan explicitly includes cost contingencies and ranges of potential benefit/cost ratios depending on how much contingency Xcel Energy spends and how much benefit it can deliver. Appendix A of my testimony provides a further description of the Xcel Energy AGIS business case and use of cost contingencies.

Metrics Linked to Goals and CBA Components with Baselines, Targets & Ongoing Reporting

Q. DOES THE COMPANY'S GT PLAN INCLUDE METRICS LINKED TO GOALS AND CBA COMPONENTS WITH BASELINES, TARGETS AND ONGOING REPORTING?

A. No. The Company has proposed metrics,[53] but they are not explicitly tied to the GT Plan goals or the CBA components. The Company has also not provided baselines for its proposed metrics nor recommended targets. Finally, the Company has not provided a plan for ongoing performance reporting.

Q. CAN YOU PROVIDE EXAMPLES OF GRID MODERNIZATION PLANS WITH METRICS LINKED TO GOALS AND CBA COMPONENTS WITH BASELINES, TARGETS AND ONGOING REPORTING?

[52] Minnesota PUC Docket No. E002/M-19- 666, November 1, 2019. AGIS includes AMI, FAN, FLISR and IVVO.

[53] Direct Testimony of Edward H. Baine, Schedule 2.

A. Yes, in an October 2017 order[54] authorizing the deployment of AMI by Entergy Arkansas, Inc. ("EAI"), the Arkansas Public Service Commission set clear expectations for strict adherence to the reporting requirements[55] of costs and benefits. The required performance measures include metrics to track each benefit and cost category in EAI's AMI Cost/Benefit analysis.

Also, in July of 2019, the Massachusetts Department of Public Utilities ("DPU") issued an order[56] approving statewide and utility-specific grid modernization plan metrics and reporting requirements. The DPU also required the utilities to establish baselines for comparison with the future grid-facing performance measures.

Support for New IDP Capabilities

Q. CAN YOU PROVIDE EXAMPLES OF GRID MODERNIZATION PLANS WITH SUPPORT FOR INTEGRATED DISTRIBUTION PLANNING?

A. Yes. California's comprehensive Distribution Resources Plan ("DRP") proceeding,[57] initiated in 2014, encompasses a wide range of IDP activities including improved forecasting and load modeling, hosting capacity analysis, locational net benefits analysis, publication of grid needs, and explicit consideration of non-utility DER to provide grid services as NWA. In a 2018 decision,[58] the California Public Utilities Commission established definitions, a classification framework, and plan submission

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[54] http://www.apscservices.info/pdf/16/16-060-U_93_1.pdf, pp. 112-113.
[55] http://www.apscservices.info/pdf/16/16-060-U_78_1.pdf.
[56] https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11006045.
[57] https://www.cpuc.ca.gov/General.aspx?id=5071.
[58] http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=212432689.

requirements for grid modernization including guidance for how the plans should support the larger DRP process.

Q. DOES THE COMPANY'S GT PLAN INCLUDE SUPPORT FOR IDP?

A. Yes. As part of its GT Plan Petition, the Company included a white paper that explains its plan for transitioning to IDP.[59] The white paper calls for:

- Comprehensive feeder level forecasting
- Hosting Capacity Analysis
- More granular time-series load modeling
- DER forecasting/scenario analysis
- NWA analysis

As I explain later in my testimony, I recommend that the Company expand its approach to NWA. DEV seems to acknowledge this opportunity, stating, "The Company defines ... IDP as a process to address the capacity, reliability, and DER integration needs of the distribution grid using traditional solutions as well as new solutions offered by customer-owned DER and other non-traditional technologies."[60]

Stakeholder Engagement During Planning and Implementation

Q. DOES DEV'S GT PLAN INCLUDE STAKEHOLDER INVOLVEMENT DURING PLANNING AND IMPLEMENTATION?

A. Somewhat. The Company met with stakeholders and incorporated feedback into the current version of its GT Plan.[61] The Company states that it "plans to continue stakeholder engagement on the GT Plan in the future. The Company intends to work

[59] Plan Document Appendix B.
[60] *Id.*, p. 1.
[61] Company response to Staff Interrogatory No. 4-58.

with stakeholders to determine the best structure, process, and cadence going forward."[62]

Increased Transparency of Distribution System Data

Q. DOES DEV'S GT PLAN RESULT IN INCREASED TRANSPARENCY OF DISTRIBUTION SYSTEM DATA?

A. Somewhat. Other than its plan to develop and publish the results of a Hosting Capacity Analysis, the Company has not described how it intends to increase the transparency of distribution system data.

Q. WHY IS THIS IMPORTANT?

A. As I mentioned previously, IDP involves explicitly considering non-utility DER to provide grid services as NWA solutions. By sharing distribution system data, such as load forecasts, grid needs, and beneficial locations, utilities can more easily collaborate with customers and developers to implement such solutions.

Q. CAN YOU PROVIDE EXAMPLES OF INCREASED TRANSPARENCY OF DISTRIBUTION SYSTEM DATA?

A. Yes. In New York, the regulated utilities have established a common portal that discloses capital investment plans, reliability statistics, planned resiliency/reliability projects, hosting capacity, beneficial locations, historical load data, load forecasts, queued and installed DG, and NWA opportunities.[63]

Enablement of De-Carbonization and Beneficial Electrification

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[62] Plan Document, p. 35.
[63] https://jointutilitiesofny.org/system-data/.

Q. DOES THE COMPANY'S GT PLAN ENABLE DE-CARBONIZATION AND BENEFICIAL ELECTRIFICATION?

A. Yes, the Company explains that:

> The Grid Transformation and Security Act of 2018 ("GTSA") established specific renewable energy and energy efficiency goals and required utilities to develop grid transformation plans to facilitate achievement of these targets. Governor Northam's Executive Order 43 ("EO43") requires … a plan of action to achieve the renewable energy and energy efficiency goals established in the GTSA as well as to achieve specific targets for the Commonwealth to produce 30 percent of Virginia's electricity from carbon-free sources by 2030 and 100 percent of the state's electricity from carbon-free sources by 2050.
>
> The targets and timelines set out in the GTSA and EO 43 will encourage aggressive and rapid deployment of zero-carbon renewable energy resources, including significant investments in smaller-scale distributed energy resources ("DERs") such as rooftop solar and energy storage. The Phase IB investments will ensure the distribution grid is prepared to integrate safely and reliably the significant amount of non-dispatchable intermittent solar and wind resources and the multitude of randomly dispersed DERs to be deployed in connection with goals of the GTSA and EO 43 …
>
> In addition to renewable energy and DERs, both the GTSA and EO 43 also require ambitious investments in energy efficiency to reduce energy costs for all Virginians and particularly to reduce the energy burden to low- and moderate-income communities. Such reductions in energy usage underscore the need for the foundational investments into AMI, CIP, and grid technologies to measure and manage energy usage and validate energy savings resulting from these energy efficiency investments.
>
> In terms of timeline, completing deployment of AMI within a 6-year window as proposed in Phase IB will enable the Company to realize the full value of the proposed grid technologies in supporting the integration of the large-scale renewables and DERs as well as the energy efficiency goals established in EO 43.[64]

[64] Company response to Staff Interrogatory No. 4-59.

Q. CAN YOU PROVIDE ANOTHER EXAMPLE OF HOW GRID MODERNIZATION PLANS CAN ENABLE DECARBONIZATION AND BENEFICIAL ELECTRIFICATION?

A. Yes. The New Jersey Draft 2019 Energy Master Plan was released in June 2019 and presents a roadmap for achieving the Governor's goal of 100% clean energy by 2050. "In order to realize the tandem goals of 100% clean energy and an 80% reduction in greenhouse gas emissions relative to 2006 levels by 2050 while maintaining a reliable, resilient, and affordable energy system, New Jersey must modernize its distribution grid. Grid modernization will provide the backbone on which all other efforts to transition to a clean energy economy will rely. The benefits of electrification, including incorporation of renewable energy, energy storage, demand flexibility, energy efficiency, load shifting, resiliency, microgrids, decentralization, and decarbonization, all necessitate a 21st century transmission system and distribution grid."[65]

Inclusion of all Required Expenditures

Q. DOES THE COMPANY'S GT PLAN INCLUDE ALL REQUIRED INVESTMENTS, INCLUDING THOSE BEYOND THE INITIAL YEAR OF REQUEST?

A. Mostly. The Company's GT Plan includes all capital and O&M costs over the life of the proposed assets. However, as I previously explained, the Commission should require the Company to explicitly include cost contingencies in future GT Plan petitions.

[65] https://nj.gov/emp/pdf/Draft%202019%20EMP%20Final.pdf, p. 73

Q. CAN YOU PROVIDE AN EXAMPLE OF GRID MODERNIZATION PLANS THAT INCLUDE ALL REQUIRED EXPENDITURES, INCLUDING THOSE BEYOND THE INITIAL PERIOD OF REQUEST?

A. Yes. California has established specific requirements for what utilities must include in grid modernization plans filed during each General Rate Case ("GRC") proceeding. One of the requirements states that "If proposed budget for 3 year GRC period covers a portion of the overall cost of the proposed program, please provide the total program costs, including expenditures already incurred and remaining costs."[66]

Synergies Between Investments

Q. DOES THE COMPANY'S GT PLAN REFLECT SYNERGIES BETWEEN INVESTMENTS?

A. Somewhat. The Company intends to use AMI for improvements in meter reading, collections, etc., but also expects the investment to support enhanced load forecasting and Voltage Optimization. The Company is, however, proposing to deploy a FAN that is separate and distinct from its proposed AMI communications network. I am concerned that the Company may have overlooked synergies and may be proposing potentially redundant investments.

Q. CAN YOU PLEASE EXPLAIN WHAT YOU MEAN BY SYNERGIES BETWEEN INVESTMENTS AND PROVIDE EXAMPLES?

A. Yes. By synergies between investments, I mean utilizing a single technology for multiple applications. This is often most evident with AMI deployments, which have

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[66] CPUC D.18-03-023, Appendix A, Grid Modernization Program Requirements, 1.b.

multiple uses, including the ability to serve as the communications network for FLISR and other distribution operations applications. For example, Xcel Energy's AGIS program will deploy a single mesh communications network that will support AMI and also serve as the FAN for communicating with network devices, supporting Integrated Volt-VAR Optimization ("IVVO") and FLISR.

Investments Based on a Demonstrated Need

Q. IS THE COMPANY'S GT PLAN BASED ON A DEMONSTRATED NEED?

A. In part. Several of the Company's proposed investments in its GT Plan support the need for new IDP capabilities. The Company has demonstrated the need for its proposed CIP, as well as investments in cyber and physical security. The Company has not, however, demonstrated the need for its proposed significant investments to improve reliability.

Q. CAN YOU PROVIDE AN EXAMPLE OF A GRID MODERNIZATION PLAN WITH INVESTMENTS BASED ON DEMONSTRATED NEED?

A. Yes. Pacific Gas & Electric ("PG&E"), with some of the highest penetrations of distributed generation in the mainland U.S.,[67] recently submitted an updated grid modernization plan as part of its triennial GRC filing. PG&E's plan "[i]nclud[es] only the incremental investments necessary to meet needs that have already been identified, such as the basic visibility to understand what is happening on the grid, improved

[67] According to PG&E's December 2018 GRC application, it has 370,000 customers with a total of 4,000 MW of rooftop solar distributed generation ("DG"), or 20% of the private rooftop DG capacity in the U.S. Additionally, PG&E adds 5,000 new DG customers and 55 MW of new rooftop solar to its grid each month. (CPUC Docket No. A.18-12-009, Exhibit PG&E-1 at p. 1-5, lines 31-33, Exhibit PG&E-4 at p. 19-AtchA-4, lines 10-12).

interconnection and planning for DERs, and some ability to control certain DERs."[68] PG&E's plan proposes a "targeted investment approach focused on circuits that are expected to have significant penetration of DERs."[69]

Despite its significant DER penetrations, PG&E is not requesting approval of a DERMS. PG&E concluded from its Electric Program Investment Charge ("EPIC") Project 2.02 that no vendor currently provides the comprehensive set of DERMS capabilities it requires.[70] As DERMS functionality matures, PG&E determined that it should first "invest in foundational technology including improved data quality, modeling, forecasting, communications, cybersecurity, and a DER-aware ADMS to address the near-term impacts of DERs and grid complexity while providing the groundwork for a future DERMS system."[71]

IV. EXPANSION OF NON-WIRES ALTERNATIVES

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING NWA?

A. I recommend that the Commission require the Company to, as part of Phase IB of its GT Plan:

- Conduct one or more NWA pilots using targeted energy efficiency ("EE") or demand response ("DR") resources on the customer side of the meter, such as thermostats, batteries, pool pumps, water heaters, and/or PV systems to defer or avoid local distribution upgrades;

- Conduct one or more NWA pilots using DER financed with private capital to defer or avoid local distribution upgrades; and

[68] CPUC Docket No. A.18-12-009, Exhibit PG&E-4, p. 19-8, lines 18-23.
[69] *Id.*, p. 19-8, line 34 to p.19-9, line 2.
[70] EPIC 2.02 DERMS Final Report, January 18, 2019, p. 6
[71] *Id.*

- Develop and implement a plan for including DER developers and other third-parties in its NWA planning and implementation processes.

Q. PLEASE EXPLAIN THE IMPORTANCE OF NWA.

A. Due to a combination of growing customer interest and declining technology costs, there are increasing numbers of distributed energy resources connected to the distribution system. In many cases, these resources are financed, owned and operated by customers and third-parties. This creates a tremendous opportunity for these resources to provide grid services as NWA and reduce the need for conventional ratepayer-funded capital investments.

<u>Targeted EE and DR</u>

Q. WHAT CONCERNS DO YOU HAVE ABOUT THE COMPANY'S APPROACH TO NWA?

A. As part of its GT Plan Petition, the Company hired Quanta Technologies ("Quanta") to develop a report "to evaluate opportunities to use non-traditional solutions such as battery storage, typically referred to as NWA, to achieve the reliability and resiliency objectives of the [GT] Plan."[72] The report examines the potential to deploy Battery Energy Storage Systems ("BESS") as NWA for eleven DEV distribution capacity, reliability and voltage projects.[73]

I have several concerns about DEV's and Quanta's approach to NWA. First, I believe Quanta's assumed BESS capital cost of **[Begin Confidential]** [redacted]

[72] Direct Testimony of Robert S. Wright, Jr., at 40-41.
[73] *Id.*

[redacted] **[End Confidential]**.[74] A November 2019 Lazard analysis of the levelized cost of storage assumes an initial capital cost for 10 MW, 6-hour duration batteries between $228-450 per kWh.[75]

Second, the report focuses exclusively on BESS. **[Begin Confidential]** [redacted] **[End Confidential]** I believe it is important for the Company to consider DER beyond BESS, such as targeted EE or DER, as potential solutions for NWA.

Q. CAN YOU PROVIDE AN EXAMPLE OF AN NWA USING TARGETED EE OR DR?

A. Yes. Central Hudson Gas & Electric in New York is targeting deployment of smart Wi-Fi thermostats and pool pump controls to reduce local distribution peak demand by 16 MW in select areas. Michael Mosher, President and CEO of Central Hudson, explained "Through our Peak Perks program, we've identified areas and specific circuits that are approaching capacity on peak days and may require future upgrades to reliably serve customers when energy use is highest, typically on the hottest summer days when the use of air conditioning is maximized. By working with our customers

[74] Confidential Attachment Staff Set 2-9(t) (RCS), p. 40 (voluminous report not attached to testimony).
[75] Lazard. *Lazard's Levelized Cost of Storage Analysis—Version 5.0.* November 2019. Available at: https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf, pg. 14
[76] Confidential Attachment Staff Set 2-9(t) (RCS), p. 1 (voluminous report not attached to testimony).

to control energy use in these locations on peak days, we are seeking to avoid or postpone system upgrades in these areas, ultimately saving money for all our customers."[77]

The Peak Perks program involves an innovative utility compensation approach. Because the program aims to defer capital projects that would have otherwise resulted in earnings for Central Hudson, the utility collaborated with regulators to create a unique compensation model, which ensures the program is financially beneficial for both the utility and its customers. Instead of a traditional return-on-capital approach, Central Hudson established an incentive-based model that rewards both the utility and its customers for implementing the least-cost, best-fit alternative to traditional infrastructure upgrades. Central Hudson can earn 30% of the savings from Peak Perks as an incentive to run the program effectively, while 70% of the savings flow to ratepayers.[78]

Q. IS THE COMPANY CONSIDERING NWA USING TARGETED EE OR DR TO DEFER SYSTEM UPGRADES?

A. No. In response to a Staff interrogatory, DEV stated, "The Company's ... Programs are similar in nature to the referenced Central Hudson Peak Perks example, but are not targeted at avoiding specific upgrades."[79]

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[77] https://www.cenhud.com/news/news/july15_2016. For program details, see https://www.cenhubpeakperks.com

[78] https://www.smart-energy.com/magazine-article/optimising-benefits-load-reduction-central-hudson-gas/

[79] Company response to Staff Interrogatory No. 13-146.

Use of Private Capital

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE COMPANY'S APPROACH TO NWA?

A. Yes. The Company appears to be relying exclusively on solutions financed with utility capital and ratepayer dollars. The least-cost NWA solutions are often those that take advantage of private capital rather than using ratepayer dollars.

Q. CAN YOU PROVIDE EXAMPLES OF UTILITIES USING PRIVATE CAPITAL FOR NWA?

A. Yes. In 2018, PG&E awarded three contracts for third-party owned storage deployments, including a 10-year contract with Micronoc Inc. for a 10 MW aggregation of behind-the-meter batteries located at customer sites and interconnected to local substations within the South Bay – Moss Landing local area.[80]

Another example is the recent Bring Your Own Device ("BYOD") pilot by Green Mountain Power ("GMP"), where the utility offers bill credits to customers in exchange for control of customer-owned home battery backup systems, EV chargers, and water heaters during peak periods.[81] The GMP BYOD example is particularly interesting because participating customers with backup batteries experience improved reliability[82] while also providing peak demand reductions to benefit all customers.

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[80] https://www.pge.com/en/about/newsroom/newsdetails/index.page%3Ftitle%3D20180629_pge_proposes_four_new_cost-effective_energy_storage_projects_to_cpuc

[81] https://greenmountainpower.com/bring-your-own-device/ and https://greenmountainpower.com/wp-content/uploads/2019/03/BYOD-Terms-and-Conditions-3-11-19.pdf

[82] https://www.greentechmedia.com/articles/read/green-mountain-power-kept-1100-homes-lit-up-during-storm-outage

Q. UTILITIES ARE CONCERNED THAT THEY CANNOT RELY ON NON-UTILITY OWNED AND CONTROLLED DER TO DELIVER THE REQUIRED GRID SERVICE AT THE TIME NEEDED. DO YOU AGREE?

A. I understand the concern, however reliable control of DER does not require its ownership. In the PG&E and GMP examples above, the utilities do not own the DER but have control over the resources.

<u>**Inclusion of Third-Parties in NWA Planning**</u>

Q. PLEASE PROVIDE YOUR THOUGHTS ON THE COMPANY'S APPROACH TO NWA PLANNING.

A. The Company's NWA planning and implementation process appears to be very closed with limited participation by DER developers and other third-parties. This perhaps means that the Company may be unaware of, and not taking advantage of, the latest innovations. The Quanta report acknowledges **[Begin Confidential]** [redacted] **[End Confidential]**[83] In response to a Staff interrogatory, the Company also acknowledged the importance of this, stating, "Planning for NWA, especially at early stages, requires changes and enhancements to existing utility practices. The Company is beginning this change process including

[83] Confidential Attachment Staff Set 2-9(t) (RCS), p. 18 (voluminous report not attached to testimony).

options to engage DER developers and other third-parties in its NWA solution evaluations."[84]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[84] Company response to Staff Interrogatory No. 13-147.

Exhibit 1 - Statement of Qualifications for Curt Volkmann

Professional Experience

I am currently President and founder of New Energy Advisors, LLC, an independent consulting firm. I work with environmental and consumer advocates in a variety of regulatory proceedings related to distribution system planning, distributed energy resources, and grid modernization.

I have 35 years of experience in the utilities industry. Prior to founding New Energy Advisors, I worked for the Environmental Law & Policy Center (ELPC) in Chicago as a Senior Clean Energy Specialist. My work at ELPC focused on providing technical advice and expert witness testimony in several renewable energy and energy efficiency regulatory proceedings.

Prior to ELPC, I was employed for eighteen years by Accenture, a global management consulting and technology firm. I held several positions at Accenture, including Executive Director in Accenture's North America Utilities practice, with client leadership responsibilities for several gas, electric, and water utilities. In this role, I oversaw utility cost reduction and operational improvement programs.

Prior to Accenture, I worked for the consulting firm UMS Group, where I led multi-utility benchmarking studies examining global best practices in electric transmission and distribution. Participating utilities in the studies were from the United States, Canada, Australia, New Zealand, Europe, and Africa.

I began my professional career working for nine years at Pacific Gas and Electric in various transmission and distribution roles. This included a role as a Distribution Planning Engineer, where I evaluated the impacts of cogeneration on distribution system protection and the impacts of demand-side management programs on the deferral of distribution substation upgrades.

Education

I have a BS in Electrical Engineering from the University of Illinois at Urbana-Champaign with a concentration in Electrical Power Systems. I also received an MBA from the University of California at Berkeley with a concentration in Finance.

I held a license as a Registered Professional Electrical Engineer in California from 1987 to 1995.

Appendix A – Xcel Energy MN's AGIS Cost/Benefit Analysis

On November 1, 2019, Xcel Energy in Minnesota filed for certification of its Advanced Grid Intelligence and Security ("AGIS") Initiative. AGIS has similar components to DEV's GT Plan, namely AMI, FAN, FLISR and Integrated Volt-VAR Optimization ("IVVO"), which is similar to the Company's planned Voltage Optimization.

Xcel includes a 26% overall capital contingency in the AGIS Cost/Benefit Analysis ("CBA") and states, "A 26 percent overall contingency … at this stage of project development is very much in line with industry standards for large technical and IT projects that span multiple years, and is appropriate for the complexity, size, and integrated nature of the AGIS project."[1] Xcel distinguishes between Business Systems-related and Distribution-related contingencies due to the different nature of the work as shown below.

AGIS Project Contingencies			
AGIS Program	Business Systems	Distribution	Combined
AMI	37%	26%	27%
FAN	45%	0%	39%
FLISR	24%	12%	14%
IVVO	10%	10%	10%

The AGIS CBA also includes ranges of potential cost/benefit ratios depending on how much contingency Xcel Energy spends and how much benefit it can deliver. Xcel explains,

> We are proposing an initiative to both replace fundamental components of our system that are approaching end of life, and to add capabilities for our customers and for a future that includes greater DER, distributed intelligence, and greater customer engagement. We would not expect to save money (on a net basis) when investing in these kinds of technologies, but we believe the total value of the

[1] Northern States Power Company d/b/a Excel Energy, 2019 Integrated Distribution Plan, Minnesota Public Utilities Commission Docket No. E002/M-19-666, Direct Testimony of Michael C. Gersack, p. 160.

initiative significantly outpaces the cost of the investments. For these reasons, the AGIS investments are prudent based on the need for the investments to serve customers, as well as consideration of the customer-facing benefits, efficiencies, and system benefits they provide.[2]

[2] Xcel Energy 2019 Integrated Distribution Plan, p. 157.

APPENDIX B

COMPANY RESPONSES
TO SELECTED INTERROGATORIES

Attachment Staff Set 2-09 (b)(1)(RCS) - Summary

Year	Feeders	Reclosers to Add	Sensors	Relays	Communication Gateways	Potential CMI savings	Potential CI savings	Line Construction Costs	Line Engineering Costs	Substation Costs	Total Costs	Customers Affected	Customers By Type R	C	I	G	Critical Infrastructure Customers
Year 1	0	0	0	0	0	0	0	$0	$931,738	$0	$931,738	0	0	0	0	0	0
Year 2	12	54	52	4	4	2,616,224	36,312	$6,011,216	$688,749	$850,000	$7,549,965	47,780	43,940	3,417	5	418	13
Year 3	11	36	55	4	4	1,599,972	25,281	$4,443,542	$4,004,692	$1,180,000	$9,628,234	40,632	37,365	2,881	5	381	14
Year 4	135	284	341	43	49	8,033,133	134,688	$25,836,720	$5,258,908	$16,189,200	$47,284,828	243,437	214,359	25,063	82	3,933	274
Year 5	135	373	447	43	49	11,647,679	204,597	$33,928,440	$5,159,891	$16,189,200	$55,277,531	300,197	269,737	25,527	86	4,847	196
Year 6	134	366	439	43	48	8,027,692	144,650	$33,289,620	$4,785,827	$16,069,280	$54,144,727	311,657	281,053	26,954	79	3,571	255
Year 7	134	339	407	43	48	9,242,180	140,121	$30,876,300	$4,312,745	$16,069,280	$51,258,325	302,583	274,315	24,488	52	3,728	227
Year 8	134	306	367	43	48	7,096,939	130,712	$27,824,160	$5,280,912	$16,069,280	$49,174,352	261,354	236,440	22,382	23	2,509	128
Year 9	134	374	449	43	48	10,774,350	189,840	$34,070,400	$3,685,637	$16,069,280	$53,825,317	289,840	264,415	22,713	37	2,675	107
Year 10	134	261	314	43	48	9,160,685	133,283	$23,778,300		$16,069,280	$39,847,580	238,256	207,048	27,100	121	3,987	219

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Fourth Set

The following response to Question No. 35 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 24, 2019 has been prepared under my supervision.

Thomas G. Hulsebosch

Thomas G. Hulsebosch
Sr. Managing Director
West Monroe Partners

Question No. 35

Please refer to Attachment AG Set 1-02 (TGH). Please refer to tab 'CBA Summary — Hulsebosch,'

(a) Please explain the inconsistency between the value of $1,974.3 million for improved reliability in cell 112 and the value of $2,028.1 million for improved reliability in p. 4 Figure 1 of Mr. Hulsebosch's direct testimony.
(b) Please provide an Excel spreadsheet with links and formulas intact supporting the calculations for the $2,703.6 million PV of revenue requirement in cell 115.

Response:

(a) This inconsistency is the result of an error in the formula producing the $2,028.1 million benefit for improved reliability on page 4, Figure 1 of Mr. Hulsebosch's pre-filed direct testimony. $1,974.3 million is the correct figure, which is noted as part of the Company's errata filing on October 25, 2019.
(b) See Attachment Staff Set 4-35 (TGH).

WACC: 7.62%

Attachment Staff Set 4-35 (TGH)

Category	Rev Req Count Years	Rev Req Present Value	Rev Req Nominal Value	2019	2020	2021	2022	2023	2024	2025	2026
AMI	27.00	$ 406,534,399	$ 779,698,792	$ 3,177,018	$ 11,635,016	$ 28,191,740	$ 46,731,930	$ 60,832,494	$ 68,700,608	$ 69,137,700	$ 66,268,560
CIP/MDMS	21.00	$ 317,146,027	$ 659,624,539	$ 4,507,734	$ 10,956,578	$ 16,875,220	$ 36,122,369	$ 65,021,566	$ 44,082,106	$ 38,978,581	$ 37,663,393
Transportation Electrification (GTP)	26.00	$ 32,329,082	$ 51,566,552	$ -	$ 5,057,776	$ 11,355,033	$ 4,201,252	$ 3,885,933	$ 4,355,402	$ 2,743,558	$ 2,932,428
Transportation Electrification (DSM)	18.00	$ 18,382,729	$ 49,431,934	$ -	$ 402,292	$ 498,252	$ 722,718	$ 1,079,835	$ 1,579,251	$ 804,560	$ 1,073,094
Grid Hardening	44.00	$ 916,519,235	$ 3,127,890,752	$ 6,169,446	$ 7,624,544	$ 14,339,001	$ 26,342,530	$ 41,984,123	$ 62,483,518	$ 83,606,546	$ 101,039,692
Grid Technologies	41.00	$ 275,769,609	$ 928,736,513	$ 140,992	$ 969,239	$ 2,714,741	$ 6,064,234	$ 12,287,050	$ 18,973,528	$ 25,254,863	$ 31,015,372
Operational Control Systems	20.00	$ 96,593,211	$ 190,877,821	$ -	$ 2,206,295	$ 4,533,644	$ 9,355,481	$ 13,568,441	$ 14,548,979	$ 16,291,373	$ 16,441,410
Time-Varying Rates/Programs	22.00	$ 46,071,094	$ 119,890,517	$ -	$ 739,979	$ 829,565	$ 842,687	$ 908,283	$ 923,223	$ 3,370,828	$ 8,982,389
Telecom (Approved - Phase 1)	28.00	$ 246,027,688	$ 639,675,706	$ 1,638,900	$ 1,993,259	$ 5,494,906	$ 12,155,786	$ 18,632,209	$ 23,261,638	$ 27,553,185	$ 31,268,365
Telecom (New)	27.00	$ 218,014,174	$ 539,734,997	$ -	$ 5,663,978	$ 12,201,869	$ 17,032,536	$ 21,663,709	$ 22,998,567	$ 25,016,158	$ 26,317,903
Physical Security	55.00	$ 47,355,949	$ 183,468,560	$ 65,805	$ 372,004	$ 842,353	$ 1,574,613	$ 2,510,465	$ 3,505,619	$ 4,463,888	$ 5,316,923
Cyber Security (Approved - Phase 1)	29.00	$ 1,898,635	$ 4,493,642	$ -	$ 11,800	$ 91,445	$ 168,095	$ 176,659	$ 185,147	$ 192,904	$ 288,828
Cyber Security (New)	29.00	$ 65,534,286	$ 182,863,676	$ -	$ 1,324,146	$ 2,271,698	$ 3,243,271	$ 4,351,289	$ 5,368,650	$ 6,541,804	$ 7,660,086
Customer Education	10.00	$ 7,615,562	$ 11,133,106	$ 40,000	$ 1,435,500	$ 1,758,860	$ 1,589,837	$ 1,443,434	$ 1,222,153	$ 900,996	$ 907,466
Microgrid	21.00	$ 7,813,971	$ 14,206,365	$ -	$ 533,750	$ 1,196,235	$ 1,186,791	$ 1,140,729	$ 1,095,173	$ 1,050,585	$ 1,006,934
Total		$ 2,703,605,652									

2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
$ 63,222,534	$ 60,214,957	$ 57,238,366	$ 54,093,397	$ 49,177,634	$ 39,948,963	$ 29,184,495	$ 19,545,742	$ 13,393,041	$ 9,787,078	$ 9,488,909	$ 9,189,874	$ 8,898,162	$ 782,415
$ 36,759,138	$ 36,062,204	$ 35,393,146	$ 34,724,772	$ 34,057,540	$ 33,393,032	$ 32,732,961	$ 32,071,582	$ 31,412,239	$ 30,756,695	$ 30,108,738	$ 21,115,665	$ 16,819,281	$ -
$ 3,057,300	$ 3,181,438	$ 2,038,348	$ 1,529,975	$ 1,423,039	$ 1,217,829	$ 1,029,336	$ 942,832	$ 877,623	$ 832,647	$ 806,816	$ 32,343	$ 24,733	$ 17,123
$ 1,394,045	$ 1,770,734	$ 2,206,369	$ 2,706,544	$ 3,281,992	$ 3,769,321	$ 4,308,292	$ 4,903,744	$ 5,560,957	$ 6,285,694	$ 7,084,239	$ -	$ -	$ -
$ 118,564,421	$ 133,312,753	$ 138,733,153	$ 135,042,518	$ 130,753,537	$ 126,543,511	$ 122,391,988	$ 118,279,943	$ 114,190,728	$ 110,111,501	$ 106,034,176	$ 101,956,376	$ 97,879,526	$ 93,803,662
$ 36,701,372	$ 41,704,156	$ 43,334,460	$ 42,152,220	$ 40,792,514	$ 39,456,646	$ 38,139,594	$ 36,835,179	$ 35,538,115	$ 34,244,030	$ 32,951,133	$ 31,658,420	$ 30,366,590	$ 29,078,980
$ 15,995,449	$ 15,840,960	$ 15,994,008	$ 15,062,112	$ 13,530,376	$ 11,586,099	$ 9,031,551	$ 8,227,998	$ 3,939,340	$ 1,966,282	$ 1,927,708	$ 811,979	$ 16,337	$ -
$ 9,746,601	$ 9,745,801	$ 9,815,384	$ 8,435,477	$ 6,565,162	$ 6,387,950	$ 6,832,319	$ 7,288,071	$ 6,705,438	$ 5,067,192	$ 5,159,854	$ 5,255,288	$ 5,341,425	$ 5,429,133
$ 34,794,769	$ 38,075,038	$ 39,637,874	$ 38,225,064	$ 36,697,627	$ 35,185,411	$ 33,682,706	$ 32,186,661	$ 30,701,080	$ 29,237,853	$ 27,645,363	$ 25,740,963	$ 23,263,031	$ 20,106,630
$ 28,125,461	$ 30,040,313	$ 30,349,051	$ 29,329,659	$ 28,249,690	$ 27,177,492	$ 26,110,720	$ 25,044,139	$ 23,996,012	$ 22,994,211	$ 22,046,548	$ 19,772,870	$ 16,744,202	$ 14,438,746
$ 6,042,001	$ 6,394,670	$ 6,375,762	$ 6,234,560	$ 6,097,650	$ 5,943,594	$ 5,801,441	$ 5,660,239	$ 5,519,988	$ 5,379,738	$ 5,239,487	$ 5,099,712	$ 4,959,937	$ 4,821,113
$ 381,903	$ 377,650	$ 361,141	$ 344,277	$ 231,706	$ 126,274	$ 124,657	$ 125,043	$ 127,224	$ 129,432	$ 132,170	$ 134,971	$ 137,339	$ 139,750
$ 8,297,510	$ 8,932,491	$ 8,882,902	$ 8,582,314	$ 8,590,019	$ 8,366,970	$ 8,094,393	$ 8,081,705	$ 8,113,030	$ 8,642,640	$ 8,732,884	$ 8,806,142	$ 9,100,334	$ 9,056,134
$ 914,065	$ 920,796	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 963,899	$ 921,339	$ 878,819	$ 836,304	$ 793,796	$ 751,306	$ 708,846	$ 666,377	$ 392,197	$ 31,867	$ 24,257	$ 16,171	$ 8,561	$ 2,378

19230011

2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
$ 448,997	$ 213,559	$ 77,052	$ 17,123	$ 1,427	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 10,940	$ 6,659	$ 3,805	$ 1,903	$ 476	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 89,763,881	$ 85,791,195	$ 81,956,919	$ 78,309,566	$ 74,860,552	$ 71,603,217	$ 68,528,050	$ 65,619,829	$ 62,830,992	$ 60,036,865	$ 57,346,067	$ 54,605,268	$ 51,842,138	$ 48,845,906
$ 27,800,833	$ 26,543,575	$ 25,327,193	$ 24,167,394	$ 23,066,567	$ 22,021,870	$ 21,032,838	$ 20,097,583	$ 19,200,895	$ 18,314,815	$ 17,343,767	$ 16,117,444	$ 14,917,404	$ 12,640,770
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 5,518,437	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 17,205,511	$ 14,827,929	$ 12,718,044	$ 10,869,035	$ 9,154,762	$ 7,593,055	$ (951)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
$ 12,886,693	$ 11,965,923	$ 11,097,677	$ 10,283,405	$ 9,472,398	$ 8,665,017	$ (476)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
$ 4,685,143	$ 4,553,929	$ 4,428,898	$ 4,311,953	$ 4,203,094	$ 4,101,845	$ 4,007,731	$ 3,918,849	$ 3,832,820	$ 3,747,742	$ 3,662,665	$ 3,577,112	$ 3,491,559	$ 3,406,481
$ 142,208	$ 144,711	$ 147,261	$ 26,227	$ 19,971	$ 14,103	$ 8,145	$ 2,572	$ -	$ -	$ -	$ -	$ -	$ -
$ 9,616,205	$ 9,833,210	$ 9,837,097	$ 1,174,961	$ 749,293	$ 349,377	$ 199,758	$ 63,366	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068
$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 45,114,387	$ 39,904,164	$ 32,953,646	$ 25,562,038	$ 18,803,282	$ 12,652,567	$ 7,170,231	$ 2,550,927	$ (3,329)	$ -	$ -	$ -	$ -	$ -
$ 10,251,179	$ 8,033,685	$ 6,033,820	$ 4,210,310	$ 1,242,534	$ (1,427)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
$ 3,321,404	$ 3,235,851	$ 3,150,773	$ 3,065,696	$ 1,970,143	$ 1,884,590	$ 1,799,512	$ 1,714,435	$ 1,628,882	$ 1,535,017	$ 1,406,212	$ 1,250,305	$ 1,065,565	$ 847,904
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080
$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ -
$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ -
$ 634,020	$ 431,996	$ 256,495	$ 107,836	$ 20,541	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ -

Dominion Energy
Company Exhibit No.___, EHB
Schedule __
Customer Benefits

Attachment Staff Set 4-39(1) (TGH)

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

Page 1 of 1
Witness Responsible:
Tom Hulsebosch

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Present Value Asset Life Total (Calculations)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
1	Customer Benefits							
2	Total Avoided/Deferred Capital		$ 657,720	$ 8,283,975	$ 10,235,580	$ 375,805,649	$ 375,805,649	Line 10
3	Total O&M Savings		$ -	$ 2,031,834	$ 5,843,195	$ 260,705,250	$ 260,705,250	Line 100
4	Total Energy/Demand Benefit		$ -	$ 80,292	$ 166,512	$ 237,538,720	$ 237,538,720	Line 200
5	Total Improved Reliability Benefit		$ -	$ -	$ 11,354,656	$ 1,974,308,424	$ 1,974,308,424	Line 239
6	Total Reduction of Bad Debt & Energy Diversion		$ 1,230,830	$ 2,250,491	$ 4,999,690	$ 118,887,075	$ 118,887,075	Line 276
7	Total Customer Benefits		$ 1,888,550	$ 12,696,592	$ 32,599,633	$ 2,967,245,117	$ 2,967,245,117	Sum Lines 2-6
8								
9								
10	Avoided/Deferred Capital Benefit Detail		$ 657,720	$ 8,283,975	$ 10,235,580	$ 375,805,649	$ 375,805,649	Sum Lines 12-95
11								
12	Avoided AMR/Walk-Up Equipment Upgrade/Replacement (AMI)	Nate Frost	$ 72,720	$ 1,012,909	$ 74,249	$ 2,986,205	$ 2,986,205	Sum Lines 13-18
13	Handheld Equipment Replacement (One-Time) ($)		-	940,252	-			Dominion Projection
14	AMR Head-End Systems Licensing (One-Time) ($)		$ -	$ -	$ -			Dominion Projection
15	Itron AMR Mobile Set-Up Fee (One-Time) ($)		$ 250	$ -	$ -			Dominion Projection
16	Itron AMR Mobile Subscription (Annual) ($)		$ 71,000	$ 72,656	$ 74,249			Dominion Projection
17	AMR Professional Services (One-Time) ($)		$ 1,470	$ -	$ -			Dominion Projection
18	AMR License/Maintenance Fees (Annual) ($)		$ -	$ -	$ -			Dominion Projection
19								
20	Avoided AMR Meter Replacement (AMI)	Nate Frost	$ 585,000	$ 2,288,025	$ 4,786,211	$ 66,712,729	$ 66,712,729	Line 21*Line 22
21	AMR Meter Replacement Forecast (#/year)		13,000	50,845	106,360			Dominion Projection
22	AMR Meter Replacement Cost ($/meter)		$ 45	$ 45	$ 45			Dominion Projection
23								
24	Avoided CBMS Mainframe Capital Maintenance (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 2,771,988	$ 2,771,988	Sum Lines 25-27
25	Internal Labor		$ -	$ -	$ -			Dominion Projection
26	3rd Party Labor		$ -	$ -	$ -			Dominion Projection
27	Hardware/Software		$ -	$ -	$ -			Dominion Projection
28								
29	Avoided Capital Run Rate (CIP)	Thomas Arruda	$ -	$ 4,528,149	$ 4,671,806	$ 35,920,194	$ 35,920,194	Sum Lines 30-32
30	Internal Labor		$ -	$ 411,650	$ 424,710			Dominion Projection
31	3rd Party Labor		$ -	$ 4,116,499	$ 4,247,096			Dominion Projection
32	Hardware/Software		$ -	$ -	$ -			Dominion Projection
33								
34	Avoided T&D Upgrade Investment (Time-Varying Rates)	Greg Morgan	$ -	$ 55,070	$ 110,242	$ 7,066,693	$ 7,066,693	Line 35*Line 36
35	Annual Incremental DEMAND Reduction from Time-Varying Rates (kW) - Residential		0	237	475			Dominion Projection
36	T&D Value of Peak Demand Reduction ($/kW)		$ 232	$ 232	$ 232			Dominion Projection
37								
38	Avoided T&D Upgrade Investment (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 15,583,255	$ 15,983,255	Line 39*Line 40
39	Annual DEMAND Reduction from Peak-Time Rebate (kW) - Residential		-	-	-			Dominion Projection
40	T&D Value of Peak Demand Reduction ($/kW)		$ 232	$ 232	$ 232			Dominion Projection
41								
42	Avoided T&D Upgrade Investment (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 99,602	$ 99,602	Line 43*Line 44
43	Annual DEMAND Reduction from Prepay Program (kW) - Residential		-	-	-			Dominion Projection
44	T&D Value of Peak Demand Reduction ($/kW)		$ 232	$ 232	$ 232			Dominion Projection
45								
46	Reduction in Future Capital from Carrier Cellular costs (Telecom)	Bradley Carroll	$ -	$ 20,467	$ 20,915	$ 330,664	$ 330,664	Line 47*Line 48
47	Installation Cost per Cellular Modem		$ 10,000	$ 10,233	$ 10,458			Dominion Projection
48	Number of Copper + MAS sites where communications would be upgraded (per year)		-	2	2			Dominion Projection
49								
50	Avoided T&D Upgrade Investment (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 11,914,382	$ 11,914,382	Line 51*Line 52
51	Peak Demand Reduction from Voltage Optimization (kW)		-	-	-			Dominion Projection
52	T&D Value of Peak Demand Reduction ($/kW)		$ 232	$ 232	$ 232			Dominion Projection

Dominion Energy
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Tom Hulsebosch

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(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
53								
54	Avoided Mainfeeder Maintenance - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 4,641	$ 2,512,143	$ 2,512,143	Dominion Projection
55								
56	Avoided Mainfeeder Outage Truck Roll - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ 1,095	$ 3,249	$ 639,961	$ 639,961	Line 57*Line 58*Line 59
57	Avoided Storm Outage Events per year (Cumulative #)		0	17	48			Dominion Projection
58	Maintenance Cost per Storm Outage Event ($/event)		$ 919	$ 946	$ 976			Dominion Projection
59	Capital Maintenance % of total (%)		7%	7%	7%			Dominion Projection
60								
61	Avoided Mainfeeder Storm Outage Truck roll - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ 127	$ 266	$ 59,030	$ 59,030	Line 62*Line 63*Line 64
62	Avoided Storm Outage Events per year (Cumulative #)		0	2	4			Dominion Projection
63	Truck Roll Cost per Outage Event ($/event)		$ 919	$ 946	$ 976			Dominion Projection
64	Capital Maintenance % of total (%)		7%	7%	7%			Dominion Projection
65								
66	Avoided Mainfeeder Storm Pole Replacements - Capital (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 11,546	$ 2,252,516	$ 2,252,516	Dominion Projection
67								
68	Avoided Outage Truck Rolls - Capital Maintenance (Targeted Corridor Improvement)	Robert Wright	$ -	$ 95,559	$ 98,590	$ 333,062	$ 333,062	Line 69*Line 70*Line 71
69	Avoided Outage Events per year (#)		-	$ 1,443	$ 1,443			
70	Truck Roll Cost per Outage Event ($/event)		$ 919	$ 945	$ 976			
71	Capital Maintenance % of total (%)		7%	$ 0	$ 0			
72								
73	Avoided Service Transformer Overload Failure - Capital Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 5,871	$ 248,822	$ 248,822	Line 74*Line 75*Line 76
74	Avoided Transformer Failures per year (#)		0	0	86			Dominion Projection
75	Maintenance Cost per Transformer Failure ($/event)		$ 919	$ 946	$ 976			Dominion Projection
76	Capital Maintenance % of total		7%	7%	7%			Dominion Projection
77								
78	Avoided Poor Health Transformer Replacement (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 171,027,338	$ 171,027,338	Line 79*Line 80
79	Cost per Transformer ($)		$ -	$ -	$ -			Dominion Projection
80	Transformer Replacements Avoided		-	-	-			Dominion Projection
81								
82	Avoided Poor Health Transformer Outage - Capital Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 4,442	$ 4,442	Line 83*Line 84*Line 85
83	Avoided Transformer Failures per year (#)		0	0	0			Dominion Projection
84	Maintenance Cost per Transformer Failure ($/event)		$ 919	$ 946	$ 976			Dominion Projection
85	Capital Maintenance % of total		0%	0%	0%			Dominion Projection
86								
87	APM - Deferred Capital Spend (EAMS)	Robert Wright	$ -	$ -	$ -	$ 2,902,263	$ 2,902,263	Line 88*Line 89
88	Distribution Recloser Asset Value Impacted		$ -	$ -	$ -			Dominion Projection
89	Deferred Capital Value of Extending Assets by 3-5 Years		0%	0%	0%			Dominion Projection
90								
91	Centralized Inventory - Avoided Capital Spend (EAMS)	Robert Wright	$ -	$ -	$ -	$ 818,920	$ 818,920	Line 92*Line 93
92	Amount of distribution inventory managed by applications		$ 135,000,000	$ 138,149,024	$ 141,177,935			Dominion Projection
93	Improved inventory forecasting		0%	0%	0%			Dominion Projection
94								
95	Avoided T&D Upgrade Investment (Transportation Electrification)	Nate Frost	$ -	$ 282,576	$ 447,992	$ 51,221,438	$ 51,221,438	Line 96*Line 97
96	Peak Demand Reduction from Managed Charging (kW)		$ -	$ 1,218	$ 1,931			
97	T&D Value of Peak Demand Reduction ($/kW)		$ 232	$ 232	$ 232			
98								
99								
100	O&M Savings Benefit Detail		$ -	$ 2,081,834	$ 5,843,195	$ 260,705,250	$ 260,705,250	Sum Lines 102-191
101								
102	Reduction in AMR Meter Reading Expense (AMI)	Nate Frost	$ -	$ 244,102	$ 2,165,817	$ 102,376,399	$ 102,376,399	Sum Lines 103, 104
103	Reduction in AMR Meter Reading Labor Expense ($)		$ -	$ 193,692	$ 1,766,029			Dominion Projection
104	Reduction in AMR Meter Reading Vehicle Expense ($)		$ -	$ 45,410	$ 399,788			Dominion Projection
105								

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Dominion Energy
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Customer Benefits

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Tom Hulsebosch

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(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
106	Reduction in Meter Servicing Expense (AMI)	Nate Frost	$ -	$ 112,147	$ 995,221	$ 47,111,666	$ 47,111,666	Sum Lines 107, 108
107	Reduction in Meter Servicing Labor Expense ($)		$ -	$ 93,543	$ 831,440			Dominion Projection
108	Reduction in Meter Servicing Vehicle Expense ($)		$ -	$ 18,603	$ 163,780			Dominion Projection
109								
110	Reduction in 'Found On' Operations Expense (AMI)	Nate Frost	$ -	$ 30,615	$ 269,528	$ 11,936,036	$ 11,936,036	(Line 112 - Line 113)*Line 111
111	Cost per 'Found On' Truck Roll ($/found on/year)		$ 265.96	$ 272.16	$ 278.13			Dominion Projection
112	Baseline Found On Truck Rolls per Year (#)		5,925	5,925	5,925			Dominion Projection
113	Projected Remaining Found On Truck Rolls per Year (#/year)		5,925	5,813	4,956			Dominion Projection
114								
115	Reduction in Meter Re-Reads (AMI)	Nate Frost	$ -	$ 3,472	$ 6,410	$ 177,494	$ 177,494	Line 116*Line 117*Line 118
116	Baseline Meter Re-Reads per Year (#)		215	215	215			Dominion Projection
117	Cost per Re-Read ($/Re-Read)		$ 119.07	$ 121.85	$ 124.52			Dominion Projection
118	Benefits Realization Factor (%)		0%	13%	24%			Dominion Projection
119								
120	Billing Process Improvement Benefits (AMI)	Nate Frost	$ -	$ 57,312	$ 105,800	$ 2,929,771	$ 2,929,771	Dominion Projection
121								
122	Reduction in Customer Calls (AMI)	Nate Frost	$ -	$ 243,597	$ 449,689	$ 12,452,652	$ 12,452,652	Line 123*Line 124*Line 125*Line 126
123	SC Scalar - "Residential" (Year End Cumulative #)		-	472,309	853,195			Dominion Projection
124	Estimated Number of Calls per Year per Customer (#)		1.40	1.40	1.40			Dominion Projection
125	Current Cost per Call ($/call)		$ 3.60	$ 3.68	$ 3.76			Dominion Projection
126	Reduction in number of customer calls due to AMI (%)		10%	10%	10%			Dominion Projection
127								
128	Billing Process Improvement Benefits (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 813,175	$ 813,175	Dominion Projection
129								
130	Avoided CBMS Mainframe Maintenance Expense (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 28,452,548	$ 28,452,548	Sum Lines 131-133
131	Internal Labor		$ -	$ -	$ -			Dominion Projection
132	3rd Party Labor		$ -	$ -	$ -			Dominion Projection
133	Hardware/Software		$ -	$ -	$ -			Dominion Projection
134								
135	CSR Savings (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 319,961	$ 319,961	Line 136*Line 137*Line 138*Line 139*Line 140
136	Projected Residential Customers on Prepay (# per Year)		0	0	0			Dominion Projection
137	Estimated Number of Calls per Year per Customer (#)		1.4	1.4	1.4			Dominion Projection
138	Percent Calls not Outage Related (%)		95%	95%	95%			Dominion Projection
139	Current Cost per Call ($/call)		$3.60	$3.70	$3.82			Dominion Projection
140	Reduction in number of customer calls due to Prepay (%)		25%	25%	25%			Dominion Projection
141								
142	Reduction in O&M from Leased MPLS costs (Telecom)	Bradley Carroll	$ -	$ 90,922	$ 334,137	$ 26,847,841	$ 26,847,841	Line 143*Line 144
143	Cumulative Sites to be Replaced (#)		0	8	28			Dominion Projection
144	Cost per Year for Leased Carrier Ethernet/MPLS		$ 10,824	$ 11,365	$ 11,933			Dominion Projection
145								
146	Reduction in Future O&M from Carrier Cellular costs (Telecom)	Bradley Carroll	$ -	$ 720	$ 1,440	$ 99,503	$ 99,503	Line 147*Line 148
147	Cumulative Sites to be Replaced (#)		0	3	6			Dominion Projection
148	Cost per Year for Leased Carrier Ethernet/MPLS		$ 240	$ 240	$ 240			Dominion Projection
149								
150	Total Avoided Capital and O&M costs for New Leased LTE (Telecom)	Bradley Carroll	$ -	$ 13,151	$ 78,905	$ 2,414,386	$ 2,414,386	Line 151*Line 152
151	Avoided Costs to Carrier per Device per Year		$ 72	$ 72	$ 72			Dominion Projection
152	Cumulative Devices Replaced		0	183	1,096			Dominion Projection
153								
154	Avoided Mainfeeder Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 1,703	$ 851,301	$ 851,301	Dominion Projection
155								
156	Avoided Mainfeeder Outage Truck Rolls (Mainfeeder Hardening)	Robert Wright	$ -	$ 14,542	$ 43,163	$ 8,502,336	$ 8,502,336	Line 157*Line 158*Line 159
157	Avoided Outage Events per year (Cumulative #)		0	17	43			Dominion Projection
158	Truck Roll Cost per Outage Event ($/event)		$ -	$ 946	$ 976			Dominion Projection

Dominion Energy
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Witness Responsible:
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Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Present Value Asset Life Total (Calculations)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
159	O&M Maintenance % of total (%)		0%	93%	93%			*Dominion Projection*

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(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
160								
161	Avoided Mainfeeder Storm Outage Truck Rolls (Mainfeeder Hardening)	Robert Wright	$ -	$ 1,689	$ 3,548	$ 784,251	$ 784,251	Line 162*Line 163*Line 164
162	Avoided Storm Outage Events per year (Cumulative #)		0	2	4			Dominion Projection
163	Truck Roll Cost per Storm Outage Event ($/event)		$ -	$ 946	$ 976			Dominion Projection
164	O&M Maintenance % of total (%)		0%	93%	93%			Dominion Projection
165								
166	Avoided Corridor Improvement Outage Truck Rolls (Targeted Corridor Improvement)	Robert Wright	$ -	$ 1,269,567	$ 1,309,845	$ 4,424,966	$ 4,424,966	Line 167*Line 168*Line 169
167	Avoided Outage Events per year (#)		-	1,443	1,443			
168	Truck Roll Cost per Outage Event ($/event)		$ 919.36	$ 946.03	$ 976.05			
169	O&M Maintenance % of total (%)		93.0%	93.0%	93.0%			
170								
171	Avoided Transformer Overload Failure Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 78,000	$ 3,305,783	$ 3,305,783	Line 172*Line 173*Line 174
172	Avoided Transformer Overload Failures per year (#)		0	0	86			Dominion Projection
173	Maintenance Cost per Transformer Failure ($/event)		$ 919	$ 946	$ 976			Dominion Projection
174	O&M Maintenance % of total		93%	93%	93%			Dominion Projection
175								
176	THA - Avoided Transformer Outage Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 59,018	$ 59,018	Line 177*Line 178*Line 179
177	Avoided Transformer Failures per year (#)		0	0	0			Dominion Projection
178	Maintenance Cost per Transformer Failure ($/event)		$ 919	$ 946	$ 976			Dominion Projection
179	O&M Maintenance % of total		93%	93%	93%			Dominion Projection
180								
181	APM - Labor Savings (EAMS)	Robert Wright	$ -	$ -	$ -	$ 2,068,227	$ 2,068,227	Line 182*Line 183*Line 184
182	Baseline Annual Outages		47,553	47,553	47,553			Dominion Projection
183	Reduced outages caused by equipment failures (APM 2.1)		0%	0%	0%			Dominion Projection
184	Incremental Cost per Unplanned Outage ($/outage)		$485.79	$499.94	$515.80			Dominion Projection
185								
186	APM - Recovery of Warranty Leakage (EAMS)	Robert Wright	$ -	$ -	$ -	$ 127,420	$ 127,420	Line 187*Line 188*Line 189
187	Assets Under Warranty That Fail		$ 590,955	$ 604,740	$ 617,999			Dominion Projection
188	Missed Warranty Recovery (%)		35%	35%	35%			Dominion Projection
189	Increase in Warranty Recovered		0%	0%	0%			Dominion Projection
190								
191	EWP - Labor Savings (EAMS)	Robert Wright	$ -	$ -	$ -	$ 4,600,518	$ 4,600,518	Sum Lines 192-197
192	Annual Designer Savings ($)		$ -	$ -	$ -			Dominion Projection
193	Annual System Modeler Savings ($)		$ -	$ -	$ -			Dominion Projection
194	Annual Program Manager Savings ($)		$ -	$ -	$ -			Dominion Projection
195	Annual Regional Engineer Savings ($)		$ -	$ -	$ -			Dominion Projection
196	Annual Warehouse Storekeeper Savings ($)		$ -	$ -	$ -			Dominion Projection
197	Annual Materials Analyst Savings ($)		$ -	$ -	$ -			Dominion Projection
198								
199								
200	Energy & Demand Savings Benefit Detail		$ -	$ 80,292	$ 166,512	$ 237,538,720	$ 237,538,720	Sum Lines 202-220
201								
202	Energy Reduction (AMI)	Nate Frost	$ -	$ -	$ -	$ 3,560,644	$ 3,560,644	Dominion Projection
203								
204	Avoided Energy Cost (Time-Varying Rates)	Greg Morgan	$ -	$ 5,803	$ 16,796	$ 3,942,435	$ 3,942,435	Sum Lines 205, 206
205	Energy Shift Benefits		$ -	$ 2,291	$ 6,053			Dominion Projection
206	Energy Reduction Benefits		$ -	$ 3,517	$ 10,743			Dominion Projection
207								
208	Avoided Demand Cost (Time-Varying Rates)	Greg Morgan	$ -	$ 7,478	$ 29,533	$ 12,729,008	$ 12,729,008	Line 209*Line 210
209	Avoided Cost of Demand ($/kW)		$ 46	$ 32	$ 41			Dominion Projection
210	Annual DEMAND Reduction from Time-Varying Rates (kW) - Residential		-	237	713			Dominion Projection
211								
212	Avoided Energy Cost (Opt-in) (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 274,507	$ 274,507	Sum Lines 213-216

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(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
213	Energy Shift Benefits (Time-Varying Rates Participants)		$ -	$ -	$ -			Dominion Projection
214	Energy Shift Benefits (Time-Varying Rates Non-Participants)		$ -	$ -	$ -			Dominion Projection
215	Energy Reduction Benefits (Time-Varying Rates Participants)		$ -	$ -	$ -			Dominion Projection
216	Energy Reduction Benefits (Time-Varying Rates Non-Participants)		$ -	$ -	$ -			Dominion Projection
217								
218	Avoided Demand Cost (Opt-In) (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 46,284,013	$ 46,284,013	Sum Lines 219, 220
219	Purchased Power Demand Savings (Time-Varying Rates Participants)		$ -	$ -	$ -			Dominion Projection
220	Purchased Power Demand Savings (Time-Varying Rates Non-Participants)		$ -	$ -	$ -			Dominion Projection
221								
222	Avoided Energy Cost (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 10,611,700	$ 10,611,700	Line 223*Line 224
223	Annual ENERGY reduction (kWh)		-	-	-			Dominion Projection
224	Avoided Cost of Energy ($/kWh)		$ 0.03	$ 0.03	$ 0.03			Dominion Projection
225								
226	Avoided Demand Cost (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 3,299,081	$ 3,299,081	Line 227*Line 228
227	Monthly DEMAND Reduction (Residential) (Annualized) (kW)		-	-	-			Dominion Projection
228	Avoided Cost of Demand ($/kW)		$ 46.35	$ 31.50	$ 41.45			Dominion Projection
229								
230	Energy Reduction (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 103,021,325	$ 103,021,325	Dominion Projection
231								
232	Demand Reduction (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 33,754,882	$ 33,754,882	Dominion Projection
233								
234	Energy Savings from Managed Charging (Transportation Electrification)	Nate Frost	$ -	$ 28,636	$ 40,148	$ 3,481,746	$ 3,481,746	Dominion Projection
235								
236	Capacity Savings from Managed Charging (Transportation Electrification)	Nate Frost	$ -	$ 38,370	$ 80,035	$ 16,579,380	$ 16,579,380	Dominion Projection
237								
238								
239	Improved Reliability Benefit Detail		$ -	$ -	$ 11,354,656	$ 1,974,308,424	$ 1,974,308,424	Sum Lines 241-273
240								
241	Annual Residential Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 193,794	$ 36,037,744	$ 36,037,744	Dominion Projection
242								
243	Annual Small C&I Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 1,802,803	$ 292,789,098	$ 292,789,098	Dominion Projection
244								
245	Annual Large C&I Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 285,773	$ 139,933,865	$ 139,933,865	Dominion Projection
246								
247	Service Transformer - Reliability Benefit (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 5,466,451	$ 183,848,576	$ 183,848,576	Sum Lines 248-250
248	Residential Reliability Benefits ($)		$ -	$ -	$ 53,611			Dominion Projection
249	Small C&I Reliability Benefits ($)		$ -	$ -	$ 413,142			Dominion Projection
250	Large C&I Reliability Benefits ($)		$ -	$ -	$ 4,999,698			Dominion Projection
251								
252	THA Transformer - Reliability Benefit (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 154,761,679	$ 154,761,679	Sum Lines 253-255
253	Residential Reliability Benefits ($)		$ -	$ -	$ -			Dominion Projection
254	Small C&I Reliability Benefits ($)		$ -	$ -	$ -			Dominion Projection
255	Large C&I Reliability Benefits ($)		$ -	$ -	$ -			Dominion Projection
256								
257	Residential Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 1,722,778	$ 1,722,778	Dominion Projection
258								
259	Small C&I Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 11,397,124	$ 11,397,124	Dominion Projection
260								
261	Large C&I Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 122,853,117	$ 122,853,117	Dominion Projection
262								
263	Residential Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 342,586	$ 60,785,322	$ 60,785,322	Dominion Projection
264								
265	Small C&I Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 2,788,276	$ 538,790,355	$ 538,790,355	Dominion Projection

Dominion Energy
Company Exhibit No.___ EHB
Schedule __
Customer Benefits

Attachment Staff Set 4-39(1) (TGH)

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

Page 1 of 1
Witness Responsible:
Tom Hulsebosch

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Present Value Asset Life Total (Calculations)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
266								
267	Large C&I Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 474,572	$ 263,321,585	$ 263,321,585	Dominion Projection
268								
269	Residential Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 1,783,351	$ 1,783,351	Dominion Projection
270								
271	Small C&I Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 11,834,288	$ 11,834,288	Dominion Projection
272								
273	Large C&I Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 154,449,542	$ 154,449,542	Dominion Projection
274								
275								
276	Bad Debt & Energy Diversion Reduction Benefit Detail		$ 1,230,830	$ 2,250,491	$ 4,999,690	$ 118,887,075	$ 118,887,075	Sum Lines 278-291
277								
278	Bad Debt Reduction (AMI)	Nate Frost	$ -	$ 119,112	$ 1,471,532	$ 58,142,907	$ 58,142,907	Sum Lines 279, 280
279	Savings per Year due to Increased Reconnects (5-year projection) ($/year)		$ -	$ 51,821	$ 715,780			Dominion Projection
280	Savings per Year in Reduced $ for Charge-Offs (5-year projection) ($/year)		$ -	$ 67,290	$ 755,752			Dominion Projection
281								
282	Theft/Energy Diversion Recovery (AMI)	Nate Frost	$ 1,092,326	$ 1,973,214	$ 3,238,671	$ 52,163,086	$ 52,163,086	Line 283*Line 284
283	Annual Energy Theft/Diversion ($)		$ 11,500,000	$ 11,500,000	$ 11,500,000			Dominion Projection
284	Reduction in Theft/Energy Diversion (%)		9%	17%	28%			Dominion Projection
285								
286	Meter Accuracy Improvement (AMI)	Nate Frost	$ 138,504	$ 158,165	$ 289,487	$ 8,220,363	$ 8,220,363	Line 287*Line 288*Line 289
287	Residential Meter Accuracy Improvement (%) (replacing aged meters)		0.02%	0.02%	0.02%			Dominion Projection
288	Average Annual Residential Revenue ($/Residential Customer)		$ 1,598	$ 1,636	$ 1,671			Dominion Projection
289	Cumulative AMI Meters Deployed (#)		433,289	483,515	865,985			Dominion Projection
290								
291	Reduction of Uncollectible (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 360,718	$ 360,718	(Line 293/Line 292)*Line 294*Line 295
292	Residential AMI Meter Deployment (Cumulative #)		$ 422,445	$ 472,309	$ 853,195			
293	Average Customers on Prepay Program through the year		$ -	$ -	$ -			
294	Annual Uncollected Revenue per year ($)		$ 22,000,000	$ 22,000,000	$ 22,000,000			
295	Reduction of Uncollectible		25.0%	25.0%	25.0%			
296								

Attachment Staff Set 4-39(2) (TGH)

		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9
WP: Customer Benefits (Line 21) (#)	Check	13,000	50,845	106,360	187,510	305,844	478,107	728,581	254,170	0
AMR Meter Replacement Forecast (#/year)	Calculation	13,000	50,845	106,360	187,510	305,844	478,107	728,581	254,170	0
Total Estimated New Connects		31,995	32,635	33,288	33,954	34,633	35,326	-	-	-
AMR Meter Replacement Forecast (#/year)		13,000	50,845	106,360	187,510	305,844	478,107	728,581	254,170	-
Baseline # AMR Meters In-Use (2019) (#)	1,922,587									
Baseline AMR Meter Failures (2019) (#)	13,000									
Annual % Increase in AMR Meter Failures (%)	45%									
AMR Meters Remaining In-Field		1,954,582	1,974,217	1,956,660	1,884,253	1,731,376	1,460,853	982,751	254,170	-

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Fourth Set

The following response to Question No. 47 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 24, 2019 has been prepared under my supervision.

Richard C. Siepka
Manager of Distribution Grid Planning
Dominion Energy Virginia

Question No. 47

Please refer to Attachment Staff Set 1-07(6)(TGH). Please refer to tab 'Baseline Reliability Metrics,' cells E32-032. Please confirm that DEV expects CAIDI to increase and this means that when outages occur, they will last longer on average.

Response:

The Company's proposed Grid Improvement work eliminates outage events and reduces the total outage time for the targeted customers. CAIDI is calculated by dividing total outage time by total number of outage events. If the number of events are reduced to a greater extent than the total duration of events, then mathematically, CAIDI will be higher. Additionally, the CAIDI calculation does not count outages lasting less than two minutes, such as when the proposed self-healing grid investments automatically isolate mainfeeder outages and reroute power to restore large groups of customers. These automated restoration activities, and the momentary outages that result, are not included in the CAIDI calculation. As a result of the proposed Grid Improvement work, customers will experience fewer events and less total outage time.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Fourth Set

The following response to Question No. 48 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 24, 2019 has been prepared under my supervision.

Thomas G. Hulsebosch

Thomas G. Hulsebosch
Sr. Managing Director
West Monroe Partners

Question No. 48

Please refer to Attachment Staff Set 1-07(6)(TGH). Please refer to tab 'Avoided CMI and CI Summary,'

(a) Please explain how Enterprise Asset Management (EAM) can result in reduced CMI and CI.

(b) Please provide all reports, data, analysis, and spreadsheets in Excel format with formulas and links intact supporting the assumption in rows 8 and 19 that EAM contributes 0.33%, 0.67% and 1% of reductions in years 8-10 respectively.

Response:

(a) As noted in the pre-filed direct testimony of Company Witness Wright on pages 18 and 19, the planned investment in Enterprise Asset Management in concert with Advanced Analytics will enable the Company to pro-actively identify and resolve asset performance issues by scheduling the maintenance and replacement of assets in a more efficient manner. As a result, the volume and duration of outage events from unplanned outages due to asset failure will decrease, positively impacting CMI and CI.

(b) The reliability improvement benefit is spread out over the course of three years following deployment in the percentages indicated. This is based on the expected timeframe to operationalize the technology and realize the associated benefit.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Fourth Set

The following response to Question No. 58 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 24, 2019 has been prepared under my supervision.

Derek Wenger
Manager – New Technology & Renewable Programs
Virginia Electric and Power Company

Question No. 58

Please refer to the replacement page for the GT Plan, Appendix E, page 4 provided by DEV on 10/3/19. Please provide specific examples of how stakeholder feedback has informed DEV's Grid Transformation planning.

Response:

Section V.C of the Plan Document, including Appendix E, provides a description of how stakeholder feedback has informed the Company's grid transformation planning. For example, stakeholder feedback helped validate the importance and inclusion of a cost-benefit analysis, a time-varying rate strategy, and a customer education plan to highlight several new scope areas within the Company's 2019 Grid Transformation Plan focused on customer empowerment and benefit realization.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Fourth Set

The following response to Question No. 59 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 24, 2019 has been prepared under my supervision.

Derek Wenger
Manager – New Technology & Renewable Programs
Virginia Electric and Power Company

Question No. 59

Please refer to the 9/30/19 GT Plan cover letter from Robert M. Blue at the top of p. 2. Please explain specifically how the Phase IB investments proposed in DEV's filing are necessary to lay the foundation essential for reaching the objectives and timelines established by EO 43.

Response:

The Grid Transformation and Security Act of 2018 ("GTSA") established specific renewable energy and energy efficiency goals and required utilities to develop grid transformation plans to facilitate achievement of these targets. Governor Northam's Executive Order 43 ("EO 43") requires the Director of the Department of Mines, Minerals, and Energy ("DMME") in consultation with the Secretary of Commerce and Trade, the Secretary of Natural Resources, and the Director of the Department of Environmental Quality ("DEQ"), to develop a plan of action to achieve the renewable energy and energy efficiency goals established in the GTSA as well as to achieve specific targets for the Commonwealth to produce 30 percent of Virginia's electricity from carbon-free sources by 2030 and 100 percent of the state's electricity from carbon-free sources by 2050.

The targets and timelines set out in the GTSA and EO 43 will encourage aggressive and rapid deployment of zero-carbon renewable energy resources, including significant investments in smaller-scale distributed energy resources ("DERs") such as rooftop solar and energy storage. The Phase IB investments will ensure the distribution grid is prepared to integrate safely and reliably the significant amount of non-dispatchable intermittent solar and wind resources and the multitude of randomly dispersed DERs to be deployed in connection with goals of the GTSA and EO 43. Technologies such as the distributed energy resource management system ("DERMS"), voltage optimization, and other intelligent grid devices proposed in Phase IB are particularly critical to maintaining reliability and visibility of the distribution grid as renewable energy and DERs proliferate. These critical grid technologies require full deployment of AMI in order to function as intended. The CIP is also foundational to management and communication of the data that will flow from these technologies and the intermittent renewable energy resources that they support, both large and small.

In addition to renewable energy and DERs, both the GTSA and EO 43 also require ambitious investments in energy efficiency to reduce energy costs for all Virginians and particularly to reduce the energy burden to low-and moderate-income communities. Such reductions in energy usage underscore the need for the foundational investments into AMI, CIP, and grid technologies to measure and manage energy usage and validate energy savings resulting from these energy efficiency investments.

In terms of timeline, completing deployment of AMI within a 6-year window as proposed in Phase IB will enable the Company to realize the full value of the proposed grid technologies in supporting the integration of the large-scale renewables and DERs as well as the energy efficiency goals established in EO 43.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Fifth Set

The following response to Question No. 74 of the Fifth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 28, 2019 has been prepared under my supervision.

Richard C. Siepka
Manager of Distribution Grid Planning
Dominion Energy Virginia

Question No. 74

Please provide DEV's historical Momentary Average Interruption Frequency Index (MAIFI) each year from 2009-2018 and YTD 2019.

Response:

The Company does not track Momentary Average Interruption Frequency Index (MAIFI), as it does not have the necessary operational visibility of distribution grid devices with automatic reclosing capability beyond select substation circuit breakers and reclosers with communications capability.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Fifth Set

The following response to Question No. 76 of the Fifth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 28, 2019 has been prepared under my supervision as it pertains to clarification of Attachment Staff Set 2-09(b)(1) (RCS), tab 'Events', column S.

Richard C. Siepka
Manager of Distribution Grid Planning
Dominion Energy Virginia

The following response to Question No. 76 of the Fifth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 28, 2019 has been prepared under my supervision as it pertains to the ICE Model and benefit modeling.

DocuSigned by:
Thomas G. Hulsebosch
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Thomas G. Hulsebosch
Sr. Manager Director
West Monroe Partners

Question No. 76

Please refer to Attachment Staff Set 2-09(b)(1) (RCS), tab 'Events', column S.

(a) Please confirm Staff's understanding that the "Customer events eliminated" refers to the number of sustained customer interruptions avoided by deployment of FLISR.

(b) Does DEV believe the values in column S may include momentary interruptions for some or all of the "Customer events"? If no, please explain. If yes, please explain how the impact of momentary interruptions is reflected in DEV's calculation of avoided customer interruptions from FLISR and corresponding inputs to the ICE calculator.

Response:

(a) The Staff is correct in its understanding that "Customer events eliminated" refers to the number of customers that avoid a sustained service interruption for each outage event listed by deployment of FLISR.

(b) The "Customer events eliminated" values represent sustained outages to be eliminated. DEV did not quantify the number of momentary outages that could be reduced or their impact, as this information has not been historically captured. Please refer to the Company's response to Staff Set 5-74.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Seventh Set

The following response to Question No. 89 of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 5, 2019 has been prepared under my supervision.

DocuSigned by:
Thomas G. Hulsebosch
7888BABAC598483

Thomas G. Hulsebosch
Sr. Managing Director
West Monroe Partners

Question No. 89

Please refer to Attachment Staff Set 4-35(TGH). Please confirm that the formulas in cells D4:D18 are incorrect. For example, the formula in cell D4 should be =$F4+NPV(WACC,$G4:OFFSET($1-14,0,($C4-1))). If the formulas are incorrect, please provide corrected versions of the spreadsheet and all other affected documents.

Response:

Please see Attachment Staff Set 7-89 (TGH), which is an updated version of Attachment Staff Set 4-35 (TGH) with the alternative method requested by staff. Additionally, below is an updated summary view using the alternative method.

Cost/Benefit Summary (Revenue Requirement Basis)

(In Millions)

BENEFITS & COSTS	PV[1]
BENEFITS *(Asset Life)*:	
Customer	$2,975.0
Avoided/Deferred Capital	$375.8
O&M Savings	$268.4
Energy & Demand Savings	$237.5
Improved Reliability	$1,974.3
Reduction of Bad Debt & Energy Diversion	$118.9
COSTS *(Revenue Requirement)* :	$2,909.7
Total Net Benefit (Cost):	$65.3
Total Benefit/Cost Ratio:	1.02

[1] *Present Value (PV) calculated using Weighted Average Cost of Capital (WACC) of 7.62%*

	PV[1]
Additional Benefits	$85.3
Reduced GHG	$4.1
EV Ownership Savings[2]	$81.2
Economic Impact[3]	$2,829.0
Total + Additional Net Benefit (Cost):	$150.6
Total + Additional Benefit/Cost Ratio:	1.05

[2] *Adjusted to apply 7.2% benefits correlation factor to reduction associated with GTP EV*

[3] *Economic Benefits are neither included in the Total + Additional Net Benefit nor in the Total + Additional Benefit/Cost Ratio*

Red text signifies formula corrections made corresponding to Staff Set 7

Cost/Benefit Summary (Revenue Requirement Basis)

(Millions)

BENEFITS & COSTS	PV[1]
BENEFITS *(Asset U/o)*:	
Customer	$2,975.0
Avoided/Deferred Capital	$375.8
O&M Savings	$268.4
Energy & Demand Savings	$237.5
Improved Reliability	$1,974.3
Reduction of Bad Debt & Energy Div	$118.9
COSTS *(Revenue Requirement)* :	$2,909.7
Total Net Benefit (Cost):	$65.3
Total Benefit/Cost Ratio:	1.02

[1] *Present Value (PV) calculated using Weighted Average Cost of Capital (WACC) of 7.62%*

	PV[1]
Additional Benefits	$85.3
Reduced GHG	$4.1
EV Ownership Savings[2]	$81.2
Economic Impact[3]	$2,829.0
Total + Additional Net Benefit (Cost):	$150.6
Total + Additional Benefit/Cost Ratio:	1.05

[2] *Adjusted to apply 7.2% benefits correlation factor to reduction associated with GTP EV*
[3] *Economic Benefits are neither included in the Total + Additional Net Benefit nor in the Total + Additional Benefit/Cost Ratio*

Jobs Creation[4]	
Indirect Jobs	17,228
Direct Jobs	4,540

[4] *Jobs creation is calculated using a multiplier applied to Millions of $ in Total Spend*

Dominion Energy
Company Exhibit No.___, EHB
Schedule __
Telecommunications Capital and O&M

Attachment Staff Set 7-89 (TGH) Tab WP_Telecom

Red text signifies formula corrections made corresponding to Staff Set 4

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

Witness Responsible:
Bradley Carroll

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Summary of Telecommunications Capital Costs					
2						
3	Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ -	$ -	$ -	$ -	$ -
4	Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ 5,500,000	$ 3,712,500	$ 4,875,000	$ 14,087,500	$ 19,806,996
5	Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ 900,000	$ 9,440,102	$ 26,987,290	$ 37,327,391	$ 235,747,831
6	Tier 3 - Cost for Field Area Network - (Not Approved in 2018)	$ -	$ 49,064,538	$ 30,775,929	$ 79,840,467	$ 183,473,678
7	Costs to Increase the Capacity of the Network Operating Center	$ -	$ 2,975,000	$ 3,400,000	$ 6,375,000	$ 14,169,496
8						
9	Total Telecommunications Capital Costs	$ 6,400,000	$ 65,192,140	$ 66,038,219	$ 137,630,359	$ 453,198,002
10						
11						
12	Summary of Telecommunications O&M Costs					
13						
14	Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ 1,200,000	$ -	$ -	$ 1,200,000	$ 1,200,000
15	Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ -	$ -	$ -	$ -	$ 3,110,586
16	Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ -	$ 101,250	$ 315,541	$ 416,791	$ 20,753,181
17	Tier 3 - Cost for Field Area Network - (Not Approved in 2018)	$ -	$ 2,163,001	$ 2,291,540	$ 4,454,541	$ 44,511,729
18	Costs to Increase the Capacity of the Network Operating Center	$ -	$ -	$ 250,000	$ 250,000	$ 4,790,086
19						
20	Total Telecommunications O&M Costs	$ 1,200,000	$ 2,264,251	$ 2,857,081	$ 6,321,332	$ 74,365,581
21						

Key Inputs	
Asset Life	32 yrs
Required Sites for Conversion from SONET to MPLS	108
Number of Microwave Sites to Offices/Substations	55
Miles of Fiber to Offices/Substations	619
Required Base Stations for Private LTE Solution	70
Required Base Stations for 700 MHz Solution	60
Existing DA Devices Requiring new FAN CPE	3,737
New DA devices requiring FAN CPE	1,200

Dominion Energy
Company Exhibit No.___, EHB
Schedule __
Proactive Component Upgrades Capital and O&M

Attachment Staff Set 7-89 (TGH)
WP_Proactive Upgrades

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

Witness Responsible:
Robert Wright

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Summary of Proactive Component Upgrades Capital Costs					
2						
3	Service Transformer Replacement - AMI Overload	$ -	$ -	$ 4,051,904	$ 4,051,904	$ 179,809,151
4	Service Transformer Replacement - AMI Voltage	$ -	$ 707,769	$ 5,511,061	$ 6,218,830	$ 31,498,245
5	THA - Poor Health Transformers Replacement	$ -	$ -	$ 14,640,675	$ 14,640,675	$ 285,332,994
6	THA - Poor Health Transformer Monitoring	$ -	$ 2,750,000	$ 2,210,000	$ 4,960,000	$ 7,575,000
7						
8	Total Proactive Component Upgrades Capital Costs	$ -	$ 3,457,769	$ 26,413,640	$ 29,871,408	$ 504,215,389
9						
10						
11	Summary of Proactive Component Upgrades O&M Costs					
12						
13	Total Proactive Component Upgrades O&M Costs					
14						

Key Inputs	
Asset Life	34.5 yrs
Estimated Service Transformers to Replace for Load	26,700
Estimated Service Transformers to Replace for Voltage	4,634
Poor Health Transformers to Replace	90
Transformers to Monitor	159

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Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Seventh Set

The following response to Question No. 90 of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 5, 2019 has been prepared under my supervision as it relates to the cost-benefit analysis.

DocuSigned by:
Thomas G. Hulsebosch
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Thomas G. Hulsebosch
Sr. Managing Director
West Monroe Partners

The following response to Question No. 90 of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 5, 2019 has been prepared under my supervision as it relates to grid improvement projects.

Richard C. Siepka
Manager of Distribution Grid Planning
Dominion Energy Virginia

Question No. 90

Please refer to Attachment Staff Set 4-39(1)(TGH), Line No. 78. Please provide a narrative description explaining the benefit category "Avoided Poor Health Transformer Replacement (Proactive Component Upgrades)".

Response:

This benefit category represents the avoided cost associated with future replacements of poor health transformers. This benefit is for deferred capital that will not have to be spent in the future because of the proactive replacement of these transformers as part of the GT Plan. See also the Company's response to Staff Set 7-91.

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Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Seventh Set

The following response to Question No. 90 of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 5, 2019 has been prepared under my supervision as it relates to the cost-benefit analysis.

Thomas G. Hulsebosch
Sr. Managing Director
West Monroe Partners

The following response to Question No. 90 of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 5, 2019 has been prepared under my supervision as it relates to grid improvement projects.

Richard C. Stepka
Manager of Distribution Grid Planning
Dominion Energy Virginia

Question No. 90

Please refer to Attachment Staff Set 4-39(1)(TGH), Line No. 78. Please provide a narrative description explaining the benefit category "Avoided Poor Health Transformer Replacement (Proactive Component Upgrades)".

Response:

This benefit category represents the avoided cost associated with future replacements of poor health transformers. This benefit is for capital that will not have to be spent in the future because of the proactive replacement of these transformers as part of the GT Plan. See also the Company's response to Staff Set 7-91.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Seventh Set

The following response to Question No. 94 of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 5, 2019 has been prepared under my supervision.

Robin Dail Massanopoli
Manager, Metering Solutions
Virginia Electric and Power Company

Question No. 94

Please refer to Attachment Staff Set 4-39(2)(TGH), cell C10. Please provide all data, analysis, reports, and spreadsheets in Excel format with all formulas and links intact supporting the assumption of a 45% annual increase in AMR meter failures.

Response:

As noted in the Company's response to Staff Set 4-33, the Company began tracking the number of AMR meters exchanged due to failed communications modules in 2016. Below is a table showing that data, as well as the calculated percent increase year-over year.

	Exchanges completed due to failed AMR communications modules	% Increase from previous year
2016	3698	
2017	4993	35%
2018	8267	66%

While the average percent increase year-over-year calculates to 51%, with the limited amount of data available, the Company took a more conservative approach when projecting avoided cost benefits associated with AMI deployment, forecasting a 45% year-over-year increase in AMR communications module failures going forward.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Ninth Set

The following response to Question No. 110 of the Ninth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 14, 2019 has been prepared under my supervision.

DocuSigned by:
Thomas G. Hulsebosch
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Thomas G. Hulsebosch
Sr. Managing Director
West Monroe Partners

Question No. 110

For each component of DEV's GT Plan (AMI, FLISR, etc.), please provide the percent (%) and dollar value ($) of cost contingencies the Company has included in its Cost/Benefit Analysis to account for the complexity, size and associated uncertainties of the program. Please also indicate specifically where in Attachment Staff Set 7-89 (TGH) or other Attachments these contingencies are shown.

Response:

There are no specific, separate line items identified for contingency for the various components of the GT Plan. Instead, contingency costs were applied to each of the components of the GT Plan to varying degrees based on the nature of the program and the proposed spend profile. This was considered in the bottoms-up development of costs and applied within the specific cost categories where it was deemed appropriate, such as labor costs and material costs. In general terms, contingency was applied to each area somewhere between 0% and 10%.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Ninth Set

The following response to Question No. 111 of the Ninth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 14, 2019 has been prepared under my supervision as it pertains to the analysis completed by West Monroe.

DocuSigned by:
Thomas G. Hulsebosch
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Thomas G. Hulsebosch
Sr. Managing Director
West Monroe Partners

The following response to Question No. 111 of the Ninth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 14, 2019 has been prepared under my supervision as it pertains to analysis completed by the Company.

for
Derek L. Wenger
Manager – New Technology & Renewable Programs
Dominion Energy Virginia

Question No. 111

Please provide the details and results of any sensitivity analysis performed by the Company related to key assumptions in the Cost/Benefit Analysis (e.g., number of avoided transformer failures per year, 45% improvement in SAIFI, 29% improvement in SAIDI, etc.)

Response:

In the development of the GT Plan scope, the Company evaluated alternative investments, as noted in direct testimony. The resulting scope represents what the Company has determined is the most practical and optimal comprehensive GT Plan based on detailed analysis and engagement with stakeholders to drive customer value. West Monroe was not tasked with creating modeling sensitivities for each of these alternatives, nor were detailed sensitivities completed for all inputs and assumptions that drive the modeling calculations.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Ninth Set

The following **corrected** response (dated December 2, 2019) to Question No. 112 of the Ninth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 14, 2019 has been prepared under my supervision.

DocuSigned by:
Thomas G. Hulsebosch
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Thomas G. Hulsebosch
Sr. Managing Director
West Monroe Partners

Question No. 112

Please refer to the Company's response to Staff Interrogatory No. 7-89. Does DEV agree that this response shows the correct PV revenue requirements calculation and resulting Benefit/Cost Ratio for the GT Plan? If yes, does the Company intend to file an errata correction to the affected pages of the Company's Petition? If no, please explain.

Corrected Response (12-02-2019):

The Company understands the alternative suggested by Staff and believes it is a reasonable method to show PV revenue requirements. However, the Company does not agree that it is the only reasonable method for calculating net present value. The Company does not plan to file an errata at this time, but plans to make appropriate updates to the CBA, including the net present value calculation, as part of its rebuttal testimony.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Ninth Set

The following response to Question No. 113 of the Ninth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 14, 2019 has been prepared under my supervision.

Richard C. Siepka
Manager of Distribution Grid Planning
Dominion Energy Virginia

Question No. 113

Refer to the Company's response to Staff Interrogatory No. 7-95(a). Provide all data, analysis, and spreadsheets with formulas and links intact supporting the Company's assumed cost of $6,121 per project to replace a service transformer, based on historical replacement activity. For each replacement activity, please include the size (in kVA) of the replacement.

Response:

See Attachment Staff Set 9-113 (RCS).

Attachment Staff Set 9-113 (RCS)

Tab Material Pivot

	Row Labels	Sum of Amount Hist	Sum of Qty (w/o unit) Hist	
	pad	**$36,142,532**	**14,740**	$2,452.00
Voltages	25	$5,424,657	3,183	
	50	$11,081,031	5,389	
	100	$14,306,280	5,117	
	167	$3,724,722	991	
	333	$93,110	4	
	500	$1,512,732	56	
	pole	**$28,857,877**	**20,589**	$1,401.62
	15	$723,571	1,012	
	25	$6,531,158	7,608	
	50	$11,945,693	9,392	
	100	$3,320,967	1,466	
	167	$1,702,113	504	
	250	$9,793	2	
	333	$1,210,679	212	
	500	$3,413,903	393	
	Grand Total	$65,000,409	35,329	

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Ninth Set

The following response to Question No. 114 of the Ninth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 14, 2019 has been prepared under my supervision.

Jason R. Hawkins
Manager of Distribution Standards
Dominion Energy Virginia

Question No. 114

Please provide DEV's design standards for overhead and underground residential service including typical transformer size (kVA) and average customers served per transformer.

Response:
For a residential service, the demand (kW) is estimated based on several factors, including square footage of conditioned space and the type of heat.

Transformer loading is in accordance with IEEE C57.91. A residential load is assumed to have a four hour peak with 75% equivalent loading prior to the peak. This allows loading to 133% of nameplate without reducing life expectancy.

Voltage drop in the secondary conductor is calculated using the estimated demand and should not exceed 3%. The conductor impedance is based on that published by the manufacturer. The power factor for a residential service is assumed to be 95%.

Flicker due to the starting of an air conditioner is calculated only for residential services. The design criteria is not to exceed a voltage dip of 5% assuming a starting current of 30 amps per ton of air conditioning. The conductor impedance is based on that published by the manufacturer. The transformer impedance is the upper limit of the impedance range for purchased units. The assumed power factor is 0.7.

The ampacity of secondary conductor is in accordance with IEEE 835.

The above applies to overhead and underground standards.

The Company's standard sizes for single-phase transformers are 25 kVA, 50 kVA, 100 kVA, and 167 kVA. The number of customers served by a transformer varies based on many factors including customer load, proximity of customers to the transformer, voltage drop in secondary lines, and configuration of distribution lines. The Company has approximately 540,000 service transformers serving approximately 2.6 million customers, so the average is 4.6 customers per transformer.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Thirteenth Set

The following response to Question No. 145 of the Thirteenth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 25, 2019 has been prepared under my supervision.

Derek Wenger
Manager – New Technology & Renewable Programs
Dominion Energy Virginia

Question No. 145

Refer to Attachment Staff Set 7-89 (TGH), tab 'CBA Summary — Hulsebosch.'

(a) Staff understands that the Benefits in the GT Plan CBA are intended to reflect benefits actually experienced by DEV's customers. Please confirm that Staff's understanding is correct. If not, please explain.
(b) Staff understands that the Costs in the GT Plan CBA are intended to reflect costs actually incurred by DEV's customers as measured by the present value of revenue requirements. Please confirm that Staff's understanding is correct. If not, please explain.
(c) Staff understands that the present value of revenue requirements better reflects the actual impact to DEV's customers than the present value of cash flows. Please confirm that Staff's understanding is correct. If not, please explain.
(d) Staff understands that the Avoided/Deferred Capital benefit in cell 19 and the O&M Savings in cell 110 are the present value of cash flows, not the present value of revenue requirements. Please confirm that Staff's understanding is correct. If not, please explain.
(e) If Staff's understanding is correct in (a), (b), (c) and (d) above, please explain why the Company shows the Avoided/Deferred Capital benefit in cell 19 and the O&M Savings in cell 110 as the present value of cash flows, not the present value of revenue requirements.

Response:

(a) Staff's understanding is correct.
(b) Staff's understanding is correct.
(c) The Company believes that both the present value of cash flows and the present value of revenue requirements are important to consider when analyzing the prudence of investments. Accordingly, the Company has presented each view within the CBA. The

Company agrees that the present value of revenue requirements better reflects the actual impact to DEV's customers.

(d) Staff's understanding is correct.

(e) The Company chose to apply the present value of cash flows method to all GT Plan benefits. Because all benefit categories are not 'cost-of-service' in nature, a present value of revenue requirement equivalent would be inappropriate in some categories. The Company agrees that the alternative method suggested could reasonably be applied to certain benefit categories (*e.g.*, avoided capital) for comparison purposes.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Thirteenth Set

The following response to Question No.146 of the Thirteenth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 25, 2019 has been prepared under my supervision as it relates to demand-side management programs.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

The following response to Question No.146 of the Thirteenth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 22, 2019 has been prepared under my supervision as it relates to integrated distribution planning.

Richard C. Siepka
Manager of Distribution Grid Planning
Dominion Energy Virginia

Question No. 146

Refer to Attachment Staff Set 2-9(t) (RCS), pp. A5-A7. Please describe the Company's plans (if any) to implement targeted demand response and/or energy efficiency as an NWA as described in the Central Hudson Peak Perks example.

Response:

The Company's DSM Phase VII Residential Smart Thermostat Management (DR) Program and the Company's proposed DSM Phase VIII Residential Electric Vehicle (EE/DR) and (Peak-shaving) Programs are similar in nature to the referenced Central Hudson Peak Perks example, but are not targeted at avoiding specific upgrades. The Company's proposed DSM Phase VII and Phase VIII DR and peak-shaving programs are intended to avoid general infrastructure upgrades and to be available if needed to target certain areas when demand constraints may exist, but the Programs were not initially designed to avoid specific infrastructure upgrades like individual substations or transmission upgrades.

For further information, see Appendix B of the Plan Document, Section 4.3.e.

Virginia Electric and Power Company
Case No. PUR-2019-00154
Virginia State Corporation Commission Staff
Thirteenth Set

The following response to Question No.146 of the Thirteenth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 25, 2019 has been prepared under my supervision as it relates to demand-side management programs.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

The following response to Question No.146 of the Thirteenth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 22, 2019 has been prepared under my supervision as it relates to integrated distribution planning.

Richard C. Siepka
Manager of Distribution Grid Planning
Dominion Energy Virginia

Question No. 146

Refer to Attachment Staff Set 2-9(t) (RCS), pp. A5-A7. Please describe the Company's plans (if any) to implement targeted demand response and/or energy efficiency as an NWA as described in the Central Hudson Peak Perks example.

Response:

The Company's DSM Phase VII Residential Smart Thermostat Management (DR) Program and the Company's proposed DSM Phase VIII Residential Electric Vehicle (EE/DR) and (Peak-shaving) Programs are similar in nature to the referenced Central Hudson Peak Perks example, but are not targeted at avoiding specific upgrades. The Company's proposed DSM Phase VII and Phase VIII DR and peak-shaving programs are intended to avoid general infrastructure upgrades and to be available if needed to target certain areas when demand constraints may exist, but the Programs were not initially designed to avoid specific infrastructure upgrades like individual substations or transmission upgrades.

For further information, see Appendix B of the Plan Document, Section 4.3.e.

<u>Virginia Electric and Power Company</u>
<u>Case No. PUR-2019-00154</u>
<u>Virginia State Corporation Commission Staff</u>
<u>Thirteenth Set</u>

The following response to Question No. 147 of the Thirteenth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on November 25, 2019 has been prepared under my supervision.

Richard C. Siepka
~~Manager of Distribution~~ Grid Planning
Dominion Energy Virginia

Question No. 147

Refer to Attachment Staff Set 2-9(t) (RCS), p. 18, **[BEGIN CONFIDENTIAL]** [redacted]" **[END CONFIDENTIAL]** Please describe how the Company has or plans to include DER developers and other third-parties in its NWA planning phase.

Response:

Planning for NWA, especially at early stages, requires changes and enhancements to existing utility practices. The Company is beginning this change process including options to engage DER developers and other third-parties in its NWA solution evaluations. The timing of the Company's transition to integrated distribution planning is dependent on Commission approval and deployment of foundational components of the GT Plan.