e. *Alternatives/Purpose & Need*

(1) *Minimum Capacity Needs: Dominion's preferred 500 kV alternative has been designed at a capacity of 5000 megawatts (MW) in order to account for electrical losses caused by future shutdowns at Yorktown and requirements to meet NERC reliability standards specific to future growth and demand. We continue to have concerns regarding the need for this amount of capacity when only 323 MW appears to be the immediate need caused by the shutdown of Units 1 & 2 and a "no action alternative" would only result in 220 – 240 MW of load shedding. After accounting for the loss of Yorktown Units 1 and 2, please provide us with the minimum additional capacity needed to meet future growth projections in order to remain compliant with NERC. It would appear that delivering a lesser capacity, such as 2000MW, after accounting for the loss of Yorktown 1 and 2 would input 1677MW of new capacity that is otherwise not currently available. Why does this 1677MW of additional capacity not satisfy future growth, therefore requiring a 5000MW source?*

Response: There is a difference between generation capacity and transmission capacity. Generation capacity and transmission capacity cannot be directly compared on an equal or one for one basis. Generation capacity is the maximum output of power produced in megawatts that the generation facility can provide. Generation facilities routinely produce power up to their maximum capacity levels to meet load demand on the system. Transmission capacity is the maximum amount of megawatts that can flow across the line (for example, the maximum capacity of a 500 kV line is 5000 MW) but is rarely, if ever, reached. This is because some room must be left for redundancy to be available for maintenance or emergency situations in the event of outages of other system transmission lines. If transmission capacity were to be fully utilized, the reliability of the transmission system would be degraded significantly in violation of the NERC Reliability Standards, which mandate redundancy in the transmission system in order to prevent cascading power outages for contingency events. An explanation of the NERC Reliability Standards is provided in Attachment 1.

The purpose of the transmission system is to deliver bulk power from generation facilities to load centers in a reliable manner as prescribed by the NERC standards. Location of the capacity also makes a difference. The distance from which generation must be delivered to load can be quite long. The greater that distance from generation to load centers, the higher the voltage and capacity that is required to reliably deliver the power. As indicated, the Yorktown units have the ability to generate and deliver 1,141 MW of power directly into the North Hampton Roads Load Area ("NHRLA"). Because this generation is physically located in the NHRLA, the local 230 kV and 115 kV transmission system provides the means to deliver that power directly to serve that local load area. With the retirement of Yorktown generation, however, power must come from distant generation facilities outside the NRHLA, which is the function of the proposed 500 kV system. Distant generation facilities on Dominion's 500 kV system from which power must be transmitted to the Peninsula include the 1550 MW Mt. Storm Power Station in West Virginia and in Virginia the 3100 MW Bath County Pumped Storage Station, the 1345 MW Warren County Power Station, the 1800 MW North Anna Power Station and, by 2016, the 1345 MW Brunswick County Power Station, currently under construction. A 230 kV interconnection does not provide the necessary strength or capacity to gain access to that remote generation and carry power from the transmission grid that a 500 kV interconnection provides, thus a 230 kV line cannot resolve the near term and long term NERC Reliability Standard violations. Only a 500 kV line can do so. Nedwick Rebuttal, p. 5-7 (Attachment 2). This is confirmed in the consistent results of the exhaustive power flow evaluations, using NERC's required reliability criteria, that were conducted by PJM, Dominion and the SCC's independent consultant, GDS. Nedwick Rebuttal, p. 12-13 and Rebuttal Schedules 4 and 5 (Attachment 2); testimony of John Chiles of GDS, Transcript p. 1068-1083, 1099-1101, 1108-1113 (Attachment 3).

The loss of the approximately 1,141 MW of generation at Yorktown significantly increases the generation deficit on the Peninsula and requires the strong and efficient interconnection that only a 500 kV source provides, not only to replace that lost power but also to address the increased flows that occur during the loss of other lines under possible contingency outages of the other sources serving the area. It is important to recognize that the 1141 MW figure reflects the fact that oil-fired Yorktown Unit 3 is actually limited by environmental restrictions to only 8% availability, has a three-day ramp-up time, and is expected to be retired by 2020.

The inherent strength of a 500 kV line is required to bring from distant generation sources the power needed to serve the NHRLA reliably in accordance with NERC Reliability Standards, under a wide range of system operating conditions over both the short term and long term.

(2) *<u>Letters Re: Plausible Alternatives & HTLS Conductors</u>: On July 27, 2015, Save the James Alliance provided documentation (attached) to demonstrate why they feel plausible options do exist based on their proposed "Immediate and Longer Term" solutions. In addition, we were copied on a letter (attached) sent from Mr. Dan Millison to Dominion regarding the use of high-temperature low-sag (HTLS) conductors as an alternative. Please use this opportunity to offer Dominion's input into this proposed solution and alternative presented to Dominion for consideration.*

Response to Save The James Alliance Trust ("STJ") Letter:

STJ No. 1: Bob Blue's statement in 2014 that Dominion does not have the ability to operate a gas unit at Yorktown is correct. The statement in the 2007 federal operating permit application stating that "two of three boilers at Yorktown are capable of firing natural gas " refers to the fact that the units could accommodate natural gas. It did not reflect the actual availability of natural gas in the area to supply the boilers and predated Dominion's evaluation of that capacity in 2011. As reflected in Dominion's letter to the DEQ requesting extension of the MATS compliance date,

> During 2011 and into 2012, the Company was evaluating the option of converting Yorktown Unit 2 to natural gas fuel and therefore did not include Unit 2 in the deactivation notice. However, after evaluation of the potential repowering, the Company concluded that there was not enough firm gas supply to support year-round operation of gas-direct generation at Yorktown Unit 2, and that an expansion of the gas supply could not be completed until 2018. In addition, estimated costs to expand natural gas capacity to support generation in the area were significant and would exceed the cost of the transmission alternatives. On October 9, 2012, the Company notified PJM of the planned retirement of Yorktown Unit 2 effective December 31, 2014.

Letter from Pam Faggert, Chief Environmental Officer and Vice President – Corporate Compliance to Mr. David Paylor, Director of Virginia Department of Environmental Quality regarding Request for Extension of Mercury and Air Toxic Standards (MATS) Compliance date Virginia Electric and Power (Dominion Virginia Power) – Yorktown Power Station Units 1 and 2 dated May 15, 2014, p. 2. See Attachment 4. Thus, after careful evaluation, Dominion determined that there was inadequate supply of natural gas to fuel Yorktown Unit 2. That situation has not changed.

STJ No. 2: STJ has the facts exactly backwards. All of the costs of new transmission facilities allocated to Dominion by PJM are paid by Dominion's customers. Under the PJM cost allocation methodology applicable to the Proposed Project, only 12.28 % of the cost of new 500 kV transmission facilities constructed by Dominion is allocated to Dominion's customers, while approximately 99.84% of the cost of new 230 kV facilities constructed by Dominion is allocated to Dominion's customers. Nedwick Rebuttal, p. 16 (Attachment 2). Evidence in the SCC proceeding showed that, under this methodology, utilization of an underground 230 kV crossing of the James River (Alternative B) would cost Dominion customers $56.4 million annually, or approximately 5 times more than the annual cost of $11 million they would pay for the Proposed Project with the overhead 500 kV line. Swanson Rebuttal Schedule 1 (Attachment 5).

STJ No. 3: The evidence in the SCC proceeding showed that a single circuit 230 kV underground line river crossing is not viable because power flow studies showed it would overload under a number of NERC contingencies. Nedwick Rebuttal, Rebuttal Schedule 4 p. 7 (Attachment 2). The cost of a double circuit 230 kV underground alternative was also considered but the evidence showed it would cost $440.4 million, would still not resolve the identified 2015 NERC violations and would require the construction of $48.2 of additional facilities to resolve those 2015 violations plus an additional $26.7 million of additional facilities to resolve identified 2021 violations (for a total cost of $515.3 million to be electrically equivalent to the Proposed Project) and could not be built by the need date. Nedwick Rebuttal Schedule 5 (Attachment 2); Allen Rebuttal, p. 15-18 and Allen Rebuttal Schedule 4 (Attachment 6). Moreover, underground construction of a double circuit 230 kV line river crossing would have significant environmental impacts, including a 400 foot right-of-way and excavation of 36,000 cubic yards of sediment and riverbed, and would take five years to build. Thomasson Rebuttal, P. 5-7 (Attachment 7); Allen Rebuttal, p. 15 (Attachment 6). The evidence also showed that the overall reliability of an underground transmission line is less than for an overhead line because a problem on an overhead line is easier to locate and repairs to underground lines take much longer to complete. Allen Rebuttal, p. 11-13 (Attachment 6).

STJ No. 4: PJM's Baseline Reliability Assessment rejected the referenced 230 kV underground proposal because it relied on a Phase Angle Regulator ("PAR"), an electrical device that PJM considered to be overly complex to reliably address the identified NERC violations. In his written testimony before the SCC, Steve Herling, PJM's Vice President of Planning, stated that this alternative was not a viable solution because the PAR could not be set to assure operation without resulting in NERC violations. As noted in his testimony, the sponsor of this proposed alternative did not dispute PJM's analysis and associated recommendation not to approve this proposal. Herling Rebuttal, p. 18-21 (Attachment 8).

Whittier Comments: STJ also attached a set of "Comments" of Mr. Whittier, its witness in the SCC proceeding, who merely restates his views that were refuted by the evidence and refuted by the SCC's independent expert, rejected by the SCC and refuted again by the February 5, 2015 letter of Peter Nedwick of Dominion to the Corps. A summary of the evidence on this issue is provided in the SCC Hearing Examiner's Report of August 2, 2013, p. 143-151 (Attachment 9). Under the heading of "New Developments", Mr. Whittier references the proposed Atlantic Coast Pipeline as a possible source of natural gas for new generation in the NHRLA. However, that project is currently not expected to be in service until late 2018 – well after the most optimistic date for extending the Yorktown retirements. Moreover, while a spur of that pipeline is proposed to terminate in Portsmouth, no portion of that project will extend north across the James River into the NHRLA. Accordingly, the Atlantic Coast Pipeline will not provide a natural gas source for generation to replace the Yorktown retirements in the NHRLA.

Response to Millison Letter: Dominion has over twenty years of experience with the use of high temperature-low sag ("HTLS") conductors (including working with several manufacturers on the development of the current generation of this equipment) and uses them on its transmission system where appropriate. The non-viability of using HTLS conductors to replace the existing conductors as an alternative to the Proposed Project was demonstrated in the SCC proceeding's assessment of STJ witness Whittier's Alternative C, which proposed to rebuild existing 230 kV Lines #214 and 263 where they cross the James River at Newport News. The evidence showed that, in order to resolve all identified NERC Reliability Standard violations, this alternative would also require, not merely reconductoring but replacing the existing structures for virtually the entire 230 kV and 115 kV systems in the NHRLA, all the way west to the Richmond area. This was estimated to take 10 years to complete, due to limitations on safety outages of existing lines during replacement, and to cost $226 million in the short term (2015) and $404.8 million in the long term (2021). Because this alternative could not be completed by the need date and would cost significantly more than the Proposed Project, it is not an acceptable solution. Allen Rebuttal, p. 21-23 (Attachment 6).

Use of HTLS conductors for the 500 kV line would not have a significant effect. The cost would be increased by an estimated $370,000, and there would be no reduction in the number of structures required. Of the 17 required structures, there would be no change in the height of the four taller structures required to span the two river channels, the height of seven of the shorter structures would be unchanged and the height of the remaining six structures would be reduced by five to ten feet.

> *(3) <u>Meeting Availability</u>: We have provided Dominion with several potential meeting dates in August. Please continue to coordinate with your key players on availability and respond to us as soon as possible so that we can schedule this critical meeting.*

Response: Dominion appreciated the opportunity to meet with the Corps on August 12 to discuss the electric alternatives questions in the Corps' July 31 letter. That discussion has increased Dominion's understanding of those questions and expedited its ability to provide timely and responsive answers.

In summary, the following outstanding items remain for action:

- ORM upload information (scheduled for August 14, 2015)
- NOAA coordination – ongoing; Dominion is awaiting a response to its July 31, 2015 letter
- Detailed Section 106 Mitigation is being developed.

Should you have any questions or concerns, please contact me at (804) 771-6408 or courtney.r.fisher@dom.com.

Sincerely,

CRFisher

Courtney R. Fisher
Sr. Siting and Permitting Specialist

Copy: Randy Steffey, ACE
Christine Conrad, Stantec
Ben Stagg, VMRC
Larissa Ambrose, DEQ

FERC, NERC and PJM Authority and Standards for Maintaining Transmission System Reliability

The Federal Energy Regulatory Commission ("FERC") is the agency of the federal government with exclusive jurisdiction to determine and regulate the reliability of the electric transmission grid.[1] The North American Electric Reliability Corporation ("NERC") is the Electric Reliability Organization ("ERO") subject to FERC oversight. NERC has regulatory authority to develop and enforce the mandatory standards, consisting of criteria, data and methodology ("NERC Reliability Standards"), to evaluate and ensure the reliability of the bulk power system in North America.[2] Virginia Electric and Power Company ("Dominion Virginia Power" or "Dominion") is a public utility subject to FERC's regulation as to transmission of electric power and sales of electric energy for resale. Dominion is also a Virginia public service corporation and public utility whose facilities and retail rates and service are regulated by the Virginia State Corporation Commission ("SCC"). Dominion, which is required by Virginia law to be a member of an RTO, transferred operational management of its transmission facilities to, and became a transmission-owning member of, PJM Interconnection LLC ("PJM") in 2005.[3] Through the proper application of the NERC Reliability Standards, the applicable

[1] The Federal Power Act of 1938 ("FPA") grants FERC exclusive jurisdiction to regulate the transmission of electric power in interstate commerce, the sale or resale of electric power in interstate commerce and the entities engaged in such transmission and sales, called "public utilities."

[2] Following the 2003 transmission blackout in the Northeast, the Congress in 2005 clarified FERC's jurisdiction under the FPA to include approval of reliability standards for the U.S. transmission grid and to enforce compliance with those standards. The 2005 legislation directed FERC to certify and regulate NERC, whose purposes are to establish and enforce reliability standards for the transmission grid (called the "bulk-power system" in the legislation) subject to FERC review. All users, owners and operators of the bulk-power system are required by that legislation to comply with NERC reliability standards approved by FERC, and failure to comply with NERC Reliability Standards can result in civil penalties of up to $1 million per day. The 2005 transmission reliability legislation was codified as 16 U.S.C. § 824o, while its authority to impose civil penalties is found in 16 U.S.C. § 825o-1. Copies of both are attached.

The term "bulk power system" is defined in the 2005 legislation to mean "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generation facilities needed to maintain system reliability." The term "reliable operation" is defined to mean "operating the elements of the bulk-power system within equipment and electric system thermal, voltage and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cyber security incident, or unanticipated failure of system elements." The term "reliability standard" means "a requirement approved by [FERC] … the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to [FERC] review" and includes "requirements for the operation of existing bulk-power system facilities, including cyber security protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system."

[3] PJM is a FERC-regulated public utility and FERC approved RTO that manages the movement of wholesale electricity in all or parts of 13 states, including all of Virginia, and the District of Columbia. The PJM system serves 61 million people, and dispatches 183,600 MW of generation capacity over 62,500 miles of transmission lines.

regional and State regulatory authorities have determined that the Surry-Skiffes Creek-Whealton project, including the 500 kV Surry-Skiffes Creek line (collectively, the "Proposed Project"), is required to assure that the FERC-approved reliability criteria are met. As described below, violations of the criteria provided in these NERC Reliability Standards, which determine the need for construction of new transmission facilities, are determined based on the results of complex computer models required by the NERC Reliability Standards to utilize data inputs for all transmission system elements.

Equipment overheating and voltage overloads, along with system instabilities are the most common causes of transmission system failures. While one equipment failure can cause a local loss of power, such a failure can also add thermal (temperature) or voltage stress to other components in the system resulting in more widespread failure. To protect the grid from isolated or large scale cascading failure, NERC establishes mandatory reliability standards for the transmission grid that include criteria for temperature and voltage limits for each piece of equipment in an electrical transmission system. In order to meet the NERC Reliability Standards, the transmission system must have sufficient redundancy, (two or more ways of connecting point A to point B in the system, as well as sufficient capacity) to minimize the risk that the transmission system will fail resulting in large scale cascading outages. To establish the redundancy required to meet the mandatory NERC Reliability Standards, computer modeling is used to predict how system equipment such as switches, transformers and transmission lines will behave under different circumstances, including high winds and other weather events, unanticipated equipment failure, cyber-attack and swinging load levels. The computer models also account for future growth in the system and the load it serves. By way of example, a violation of these NERC Reliability Standards occurs when the computer models predict that operation of the system will cause the temperature of a piece of equipment to exceed applicable thermal limits or the operating voltage to exceed or fall below applicable maximum and minimum levels, or if insufficient redundancy exists under any of the scenarios (e.g., 230 kV Line X will overload upon the outage of 230-115 kV transformer Y at substation Z). NERC Reliability Standards require planning and operation of the system to avoid such violations; failure to do so could result in catastrophic damage to equipment resulting in long duration outages, or even worse, wide spread, cascading damage to or failure of the transmission grid.

As explained in more detail below, both PJM and the SCC independently determined for the Skiffes Creek project that only a 500kV line would reliably meet the NERC Reliability Standards; a 230 kV system would not.

I. The NERC Transmission Reliability Planning and Modeling Standards

In 2006, FERC certified NERC as the ERO and in 2007 approved mandatory transmission reliability standards proposed by NERC, including standards for planning additions to the grid, copies of which are attached, required for reliable operation ("TPL Standards"). These NERC Reliability Standards established the following planning criteria:

Category A criteria, established in NERC Reliability Standard TPL-001-0, require that, for all facilities in service (transmission lines, transformers, etc.) and no contingencies (normal system or "n'), equipment thermal ratings and system voltage limits must be maintained and that the system is stable.

Category B criteria, established in NERC Reliability Standard TPL-002-0, impose similar requirements with one facility removed from service, referred to as "n-1." These criteria ensure that the system operates to remain reliable upon the instantaneous outage of any one system element.

Category C criteria, established in NERC Reliability Standard TPL-003-0, require the system to be stable and equipment thermal ratings and system voltage limits maintained for multiple system events, including second contingencies involving the loss of one system element followed by system readjustments and then the loss of a second system element (referred to as "n-1-1"). Category C criteria also include the loss of two circuits on a single tower line or a single faulted system element followed by a stuck breaker (referred to as "n-2"), for which the criteria do not allow adjustment of generation patterns.

Category D criteria, established in NERC Reliability Standard TPL-004-0, require evaluation of extreme events resulting in two or more (multiple) elements removed from services or cascading out of service, such as loss of a line with three or more circuits and loss of all lines in a common right-of-way.

These NERC Reliability Standards are subject to review and revision by NERC, with FERC's approval. The attached copies are the versions of these standards in effect during the periods relevant to the planning processes that identified the need for the Proposed Project, including the need for the 500 kV Surry-Skiffes Creek line. FERC also approved a "Glossary of Terms used In NERC Reliability Standards," which incudes on page 13 NERC's definition of the "Bulk Electric System" or "BES" that is subject to FERC's regulation, through NERC, of transmission system reliability relevant to the planning timeframe of the Proposed Project. The Glossary can be accessed at www.nerc.com. PJM is a Transmission Planner under the NERC Glossary, while Dominion is a Transmission Owner.

These TPL Standards provide that "System simulations and associated assessments are needed periodically to ensure that reliable systems are developed to meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs." For the purposes of assuring compliance with these TPL Standards, these "system simulations and associated assessments" include complex computer models that simulate the existing and projected design, including the location and specification of the system components (also known as "topology") and steady-state operation of the transmission system, all in accordance with FERC-approved NERC Standards for Transmission System Modeling and Simulation ("NERC Modeling Standards").

The NERC Modeling Standards applicable to the need analysis for the Skiffes project are NERC Modeling Standard MOD-010-0, Steady-State Data for Modeling and Simulation of the Interconnected Transmission System, and Standard MOD-011-0, Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures, copies of which are attached. The former requires transmission owners such as Dominion and transmission planners such as PJM, as well as generators and generation resource planners, to furnish appropriate and accurate inputs for these models. NERC Modeling Standard MOD-011-0 specifies the specific data inputs required for each system element:

Bus (substation): name, nominal voltage, electrical demand supplied and location.

Generating unit: location, minimum and maximum ratings (net real and reactive power), regulated bus and voltage set point, and equipment status.

AC transmission line or circuit (overhead and underground): nominal voltage, impedance, line charging, normal and emergency ratings and equipment status, and metering locations.

DC transmission line (overhead and underground): lime parameters, normal and emergency ratings, control parameters, rectifier data, and inverter data.

Transformer (voltage and phase-shifting): nominal voltage of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings, and equipment status.

Reactive compensation (shunt and series capacitors, and reactors): nominal ratings, impedance, percent compensation, connection point, and controller device.

Interchange schedules: existing and future interchange schedules and/or assumptions.

Using these data inputs, models are developed to simulate the design and operation of each system being studied, from the individual transmission owner level, up through the RTO level to the Eastern and Western Interconnections. The model for each system serves as the basis for assessing whether the system, both existing and under projected changes in future design and operations, is in compliance with the NERC Reliability Standards. As required by the TPL Standards, these assessments are conducted annually on both a short term (5 years out) and long term (10 years out) basis.

II. Application of the NERC Reliability Standards and NERC Modeling Standards Established the Need for the Proposed Project

PJM serves as the transmission planner for the transmission system in its region, which includes the systems of each of its 19 transmission owner members. In this capacity, PJM works with its members and other stakeholders, in an open and transparent process approved by FERC, to develop an annual Regional Transmission Expansion Plan ("RTEP") that assesses the current system and its short term (years 1 through 5) and long term (years 6 through 10) needs for additions to assure compliance with the NERC Reliability Standards.

The RTEP process is implemented under PJM's Open-Access Transmission Tariff using open and transparent methodologies and criteria approved by FERC. The first step in this process is to use the data inputs provided under the NERC Modeling Standards to develop a base case power flow model that accurately simulates the design and steady-state operation of the existing PJM system. Then power flow models are developed that show projected changes to the system in 5-year and 10-year intervals into the future, including load forecasts (reflecting the impacts of demand-side management response and gains in energy efficiency), interconnections of new generation units and generation retirements, and additions of new or replacement transmission facilities and (less frequently) transmission retirements.

Each power flow model is then subjected to the scenarios prescribed in the TPL Standards and PJM's FERC-approved planning criteria for compliance with the NERC Reliability Standards, to determine whether the NERC Reliability Standards are met for each time period and for each system element. Each transmission owner in PJM also tests its own system by using the PJM base case and the transmission owner's reliability planning criteria to determine whether NERC Reliability Standards will be violated by future operations on the transmission owner's system. Any failure of a system element on the PJM system or the system of any transmission owner to meet any of the criteria constitutes a violation of the NERC Reliability Standards and must be resolved. The power flow models are used to evaluate possible solutions until a solution is found that resolves all contingencies before the future dates by which the violations would occur. This process is administered by PJM's Transmission Expansion Advisory Committee ("TEAC"), which evaluates violations of NERC Reliability Standards and recommends solutions to the PJM Board for inclusion in the annual RTEP. Each year's RTEP also updates the plan by reviewing previously approved solutions to determine whether they are still needed.

PJM determined through the RTEP process that upon the retirements of Yorktown Units 1 and 2 extensive thermal and voltage violations of NERC Reliability Standards would occur unless additional transmission systems were added in the area. For example, PJM determined that, without the Proposed Project Dominion's 230 kV Chuckatuck-Newport News Line would overload upon an outage of Dominion's 230 kV Surry-Winchester line, and that the 230 kV system in North Hampton Roads Load Area ("NHRLA") would experience a voltage collapse upon the outage of a specific double circuit 230 kV tower line. After considering both 230 kV alternatives and the 500 kV Surry-Skiffes Creek line, PJM determined that the 500 kV line reliably resolved all of the identified NERC Reliability Standard violations while the 230 kV alternatives did not. Accordingly, PJM selected the Proposed Project for inclusion in the 2011 RTEP.

III. The SCC's Determination of Need for the Proposed Project

Virginia law (Va. Code §§ 56-265.2 and 56-46.1) requires a public utility to obtain a certificate of public convenience and necessity from the SCC before the utility may construct an electric transmission line 138 kV and above. Before the SCC can approve construction of such a line, Section 56-46.1(B) requires the SCC to determine that the line is needed and, among other requirements, to "verify the applicant's load flow modeling, contingency analyses and reliability needs presented to justify the new line." The Supreme Court of Virginia has affirmed the SCC's determination of need for new transmission facilities based on violations of NERC Reliability Standards. *Piedmont Envtl. Council v. Virginia Elec. and Power Co*., 278 Va. 553, 684 S.E.2d 805 (2009).

In SCC Case No. PUE-2012-00029, the evidence showed that retirement of Yorktown Units 1 and 2 will create extensive thermal and voltage violations of NERC Category B, C and D reliability criteria in the NHRLA and that only a new 500 kV source into the NHRLA can resolve all of the identified NERC violations that would occur when the Yorktown generation units are retired. Extensive NERC-compliant power flow studies, ordered by the SCC Hearing Examiner and verified by the SCC Staff's independent consultant John Chiles, showed that any of the alternatives that would use a 230 kV crossing of the James River, instead of the new 500 kV source, either could not be built by the identified need date or, for those that could meet the need date, would require construction of additional facilities to be electrically equivalent to the Proposed Project that would cost far more than the Proposed Project. Accordingly, the SCC rejected the 230 kV alternatives and approved the new 500 kV Surry-Skiffes Creek overhead line across the James River. SCC Case No. PUE-2012-00029, Report of Alexander P. Skirpan, Jr., Senior Hearing Examiner (Aug. 2, 2013) at 129-155, and Order (Nov. 26, 2013) at 13-13-16, 19-47.

REBUTTAL TESTIMONY
OF
PETER NEDWICK
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

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

A. I am Peter Nedwick, and I am a Consulting Engineer in Electric Transmission Planning for Dominion Virginia Power. My office is located at 701 East Cary Street, Richmond, Virginia.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, my prefiled direct testimony on behalf of Dominion Virginia Power was submitted to the State Corporation Commission of Virginia (the "Commission") in this matter on June 11, 2012.

Q. What is the purpose of you rebuttal testimony?

A. I will respond to the prefiled testimony of Staff Witness John Chiles of GDS Associates, Inc. ("GDS"), who provided an independent analysis of the need for the Company's proposed Project and who also provided analysis of a set of four 230 kV transmission alternatives (two overhead and two hybrid with underwater crossings of the James River) to the Company's proposed 500 kV Surry-Skiffes Creek overhead transmission line, as well as generation alternatives. I will provide and comment on the results of a series of updated flow studies directed by the Hearing Examiner as to the proposed Project, two underground 230 kV alternative lines to Skiffes Creek Switching Station ("Skiffes provide that 500 kV source from Surry Switching Station ("Surry Station") to support the 230 kV system by extending a new 230 kV line from Skiffes Station down the Peninsula to Whealton Substation in the City of Hampton. The Company also proposed an alternative 500 kV source to Skiffes Station from Chickahominy Substation. Both 500 kV sources are electrically viable and functionally equivalent.

Q. Were Mr. Chiles and GDS able to verify the results of the Company's Power Flow Studies?

A. Yes, as noted on pages 16 and 31 of Mr. Chiles's Direct Testimony and also on page 6 of Mr. Chiles's Attachment JWC-2, GDS was able to verify the results of the Company's Power Flow Studies.

Q. Was GDS able to make a determination as to need for the Project?

A. Yes, Mr. Chiles noted on page 31 of his testimony and on page 15 of Exhibit JWC-2 that the Project adequately addresses the identified NERC Reliability Violations.

II. A 500 KV SOLUTION IS REQUIRED

Q. Did the Company propose a 230 kV alternative to the 500 kV Surry-Skiffes Creek line?

A. No. As explained in the Appendix and my direct testimony, no 230 kV solution, whether single circuit or double circuit, and whether underground, overhead, or hybrid, resolves all of the identified NERC Reliability Violations. Only a 500 kV solution does that.

Moreover, attempting to address NERC Reliability Violations on the 230 kV system in North Hampton Roads by creating another 230 kV connection into that area from South Hampton Roads (e.g., Surry Power Station), as would be the case with 230 kV

Alternatives A, B and C discussed in detail below, would merely increase the supply requirements in South Hampton Roads, which is also generation deficient.

A new 230 kV connection across the James River would merely permit more power to flow from one generation-deficient portion of the 230 kV system (South Hampton Roads) to another (North Hampton Roads). It would not solve the significant lack of bulk capacity that is needed to increase the ability of each 230 kV system to serve local load, which can only be provided by an extension of the 500 kV system into the area.

The 500 kV system is the major source of bulk power to the Company's customers. Its primary purpose is to support the reliable and safe transmission of bulk capacity and associated energy from remote generation sources to major load centers. At these major load centers, bulk power is transformed to flow from the 500 kV system to the 230 kV system to satisfy the area's capacity and energy requirements. In the South Hampton Roads Load Area, these major 500 kV to 230 kV transformations are achieved at Fentress Station, Suffolk Station, and Yadkin Station. In 2011 (pre-generation retirement), the Company built an approximately 60-mile long 500 kV line from Carson Station to Suffolk Station to support continued reliable service to the customers located in the South Hampton Roads Load Area. However, there is currently no such 500 kV source of bulk power into the North Hampton Roads Load Area.

My Rebuttal Schedule 1 shows the bulk power requirements for North and South Hampton Roads for Summer 2015 and Summer 2021 under both normal conditions and critical system conditions ("CSCs") based on the 2013 PJM Load Forecast. This schedule, including the table on page 5, demonstrates that in 2015, under normal operating conditions, North Hampton Roads Load Area will import 86.6% of its capacity from west of Richmond, while South Hampton Roads will import 52%. Under CSCs, the import requirements for North Hampton Roads increase to 99% and for South Hampton Roads to 75%. By Summer 2021, North Hampton Roads must import 87% of its capacity from west of Richmond under normal operating conditions, and 98% under CSCs, while these figures for South Hampton Roads increase to 54.6% and 76.6%, respectively. Simply increasing the capacity of existing 230 kV tie lines between two generation deficient areas or by adding an additional new 230 kV circuit between them cannot meet the need for a *new* source of bulk capacity and energy into the area most immediately in need, the North Hampton Roads Load Area.

Q. Did the Company include information regarding 230 kV alternatives in its filing?

A. Yes. Because 500 kV underground construction is not viable, we were aware that potential opponents of the proposed Surry-Skiffes Creek line might seek to have that line installed underground at 230 kV, in whole or in part, so we thought it would be helpful to provide an estimate of what that would cost. Accordingly, we provided in Section I.C of the Appendix our estimated costs for a 230 kV double circuit line from Surry Station to Skiffes Station, with either hybrid underground/overhead or all-underground installation. In addition, a 230 kV Surry-Skiffes Creek single circuit hybrid line with an underwater crossing of the James River had been proposed to PJM by a non-incumbent transmission developer subsidiary of LS Power. We also provided in Appendix Section I.C materials developed by PJM describing its analysis and rejection of the LS Power proposals, which included the developer's estimated cost of that project.

Q. Was GDS able to determine if any 230 kV alternatives were satisfactory compared to the proposed 500 kV Surry-Skiffes Creek line?

A. Yes, they were able to determine that none of the four 230 kV alternatives that they studied (single circuit hybrid underground crossing, a double circuit hybrid underground crossing, single circuit overhead crossing and a double circuit overhead crossing) resolved all the identified Reliability Violations. Furthermore on page 32 of Mr. Chiles's testimony he states:

> I do not recommend the construction of a double circuit 230 kV overhead Surry-Skiffes Creek transmission line, as it is less effective than the Project. Further, I do not recommend the construction of a 230 kV Surry-Skiffes Creek hybrid line (either single or double-circuit) due to identified reliability issues and expected cost increase and practicality to build.

III. ADDITIONAL ANALYSES

Q. How will the Company approach discussion of 230 kV alternatives in its rebuttal testimony?

A. During the public hearing held in this proceeding on January 10, 2013, the Hearing Examiner directed the Company to investigate whether a hybrid line would be feasible. This hypothetical hybrid line, at either single or double circuit 230 kV would run overhead from Surry Station to an overhead-to-underground transition station at the shore of the James River in Surry County, then cross the James River underwater and, upon coming ashore on the BASF property along the James River Variation 3 route, continue underground along that route until reaching an underground-to-overhead transition station at the intersection of the James River Crossing Variation 3 route and BASF Drive, from which the line would continue overhead north with the Proposed Route along BASF Drive and across U.S. Route 60 to Skiffes Station. On page 2 of his January 30 Ruling, 2021, which is 42 MW and 40 MW, respectively, lower than the 2012 Load Forecast. These new 2013 Load Forecast values were incorporated into the 2015 and 2021 Power Flow models, which are based on the 2012 Load Forecast, by reducing the entire Dominion Virginia Power System loads down by the 417 MW and 308 MW, respectively, in 2015 and 2021. The new 2013 Load Forecast also includes new energy efficiency and demand-side management values, which are incorporated into reliability assessments as required by the reliability assessment being conducted. The 2015 and 2021 Power Flow models were then updated to reflect any additional system changes that have occurred over the last six months.

Q. Please summarize the results of these updated studies.

A. The 2015 studies show that the Company's proposed Project resolves all identified NERC Reliability Violations, but none of the 230 kV Alternatives A, B or C is able to resolve all Reliability Violations in 2015 without constructing additional transmission and/or generation facilities. There also would be additional fuel expense, but that was not specifically quantified for purposes of the Additional Analyses.

The studies show further that the proposed Project is still needed in 2021, with the addition of a minor upgrade of a 115kV line in the area (a variation of which shows up in all the alternatives in that timeframe), and continues to resolve the identified NERC Reliability Violations. All of the 230 kV, 230 kV + generation and stand-alone generation options would require much more extensive and costly facilities to achieve the same results and could not be achieved by the 2015 need date. More detail on these results is provided in my Rebuttal Schedule 4. The actual print outs of the results are contained in Volumes III through VI of this rebuttal testimony and correspond to the

Additional Analyses designations set forth in my Rebuttal Schedule 4.

Q. What are the costs of these alternatives?

A. A detailed comparison of the costs of the proposed Project and alternatives is provided in my Rebuttal Schedule 5. The costs of the alternatives are not useful because, as I will explain in more detail, none of them could be constructed by the need date. The costs to construct 230 kV hybrid underground Alternatives A and B, and the cost of the 230 kV overhead Alternative C Newport News Crossing rebuild, are provided in the rebuttal testimony of Company Witnesses Walter R. "Trey" Thomasson, III and Mark S. Allen. The additional transmission facilities that would be required to bring Alternatives A, B and C into full compliance with NERC Reliability Standards are described on pages 11, 12 and 13 of my Rebuttal Schedule 4. The costs to construct the additional overhead transmission facilities that would be required for Alternatives A and B to be in full compliance with NERC Reliability Standards, as well as the cost of the Alternative C overhead facilities required for the rebuild of the existing James River crossing circuits, are provided in Rebuttal Schedule 4 to the rebuttal testimony of Company Witness Mark Allen. The costs of additional generation required to meet NERC Reliability Standards are provided in the rebuttal testimony of Company Witness Glenn Kelly. These combined results are summarized in Table 2 below subject to the same comments regarding constructability, timing and generation availability and costs as set forth on my Rebuttal Schedule 5.

Table 2

Alternative	2015 Total Cost	2015 Excess Over Proposed Project	2021 Total Cost	2021 Excess Over Proposed Project
Surry 500 kV (Proposed Project with Updated Proposed Route)	$155.4 M	$0.0	$172.7 M	$0.0
Chickahominy Alternative 500 kV	$213.2 M	$57.8 M	$230.5 M	$57.8 M
Surry 230 kV Alternative A	$488.6 M	$333.2 M	$515.3 M	$342.6 M
Surry 230 kV Alternative B	$488.6 M	$333.2 M	$515.3 M	$342.6 M
230 kV Alternative C	$226.9 M	$71.5 M	$408.8 M	$236.1 M
230 kV Alt A + Generation	$623.8 M	$468.4 M	$1,200.8 M	$1,028.1 M
230 kV Alt B + Generation	$540.4 M	$385.0 M	$1,117.4 M	$944.7 M
230 kV Alt C + Generation	$494.8 M	$339.4 M	$1,071.8 M	$899.1 M
Yorktown Stand-Alone Generation	$633.0 M	$477.6 M	$1,345.0 M	$1,172.3 M

Clearly, the proposed Project remains the most timely, robust and economical solution to the identified reliability violations.

Q. Why have these 230 kV alternatives been put forward?

A. James City County and a number of other Respondents have stated their opposition to any overhead crossing of the James River to Skiffes Station and no one in the case supports an overhead 230 kV line to Skiffes Station. So, when these opponents propose the use of a 230 kV line from Surry Station to Skiffes Station they do so because they want at least the James River crossing portion of such a line to be constructed underground. This means that, because using 230 kV would not address all of the identified NERC Reliability Violations in 2015, as verified by the Company in the Appendix, Staff Witness Chiles and, again, by the Company through the Additional

Analyses, the project cost of a 230 kV version of a Surry-Skiffes Creek line would include, in addition to the much higher cost of underground construction, the cost to complete the job by making additional transmission upgrades to resolve all of the NERC Reliability Violations that 230 kV cannot solve (i.e., the additional cost for full compliance facilities). This ensures an appropriate apple-to-apples comparison of costs for purposes of Commission consideration and decision-making. For example, using the Company's estimated cost to construct the 230 kV Alternative B, which will not solve the identified NERC Reliability Violations in 2015, the preliminary cost for partial compliance to construct Alternative B would be $440.4 million (provided by Company Witness Thomasson) plus the $48.2 million cost of the additional transmission upgrades required to fully comply with NERC Reliability Standards (provided by Company Witness Allen), for a total cost of $488.6 million.

The necessary inclusion of the cost of additional transmission facilities required to fix NERC Reliability Violations not addressed by the use of inadequate 230 kV facilities, and associated costs to ratepayers, is presented in greater detail in my Rebuttal Schedule 5 for each of the alternatives we were directed to study. This much greater cost, and the associated reliability and operating risks of underground construction described by Company Witness Mark Allen in his rebuttal testimony, would be incurred by all of the Company's customers in order to avoid any additional visual impacts above those that already exist from the James City County side of an overhead transmission line river crossing to Skiffes Station, as described by Company Witnesses Doug Lake and Liz Harper in more detail in their rebuttal testimonies.

Q. Does James City County indicate who would be responsible for these additional costs?

A. No, they do not.

Q. Could the use of either 230 kV and/or underground construction have an adverse impact on the Company's customers as a result of cost allocation at the federal level?

A. Yes. As the Company explained in its response to Question No. 23 of the Staff's Second Set of Interrogatories, a copy of which is attached as my Rebuttal Schedule 6, under the currently effective cost allocation methodology approved by FERC, 12.28% of the cost of a 500 kV line is allocated to the Company's customers, while 99.84% of the cost of a new 230 kV line is allocated to the Company's customers. The effect of this difference in PJM allocation methodologies is seen in Company Witness Kurt Swanson's rebuttal testimony, which demonstrates that approximately five times as much cost is allocated to the Company's customers for 230 kV facilities as for 500 kV facilities. I should also mention that Old Dominion Electric Cooperative and other wholesale customers of the Company have taken the position in recent litigation at FERC that the cost of any transmission line installed underground for local aesthetic reasons should be allocated 100% to the Company's retail customers.

Q. Did the Hearing Examiner direct the Company to examine the difference between using High Pressure Fluid Filled ("HPFF") Cable or cross-linked polyethylene ("XLPE") Cable for the 230 kV underground construction proposed for Alternative A and B?

A. Yes, and I will discuss the differences in the applications in the power flow models and in

Dominion

PUE-2012-00029

2013 Power Flow Cases Requested by Hearing Examiner

Revised April 1, 2013

Additional Analyses Conducted

- **500 kV Proposed** - Surry to Skiffes Creek 500 kV Overhead
- **Alternative A** – Hybrid Single Circuit 230 kV UG Line based on 1000 MVA
- **Alternative B** – Hybrid Double Circuit 230 kV UG Line based on 1000 MVA/circuit
- **Alternative C** - Rebuild of Lines #214 and #263

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Additional Analyses Conducted

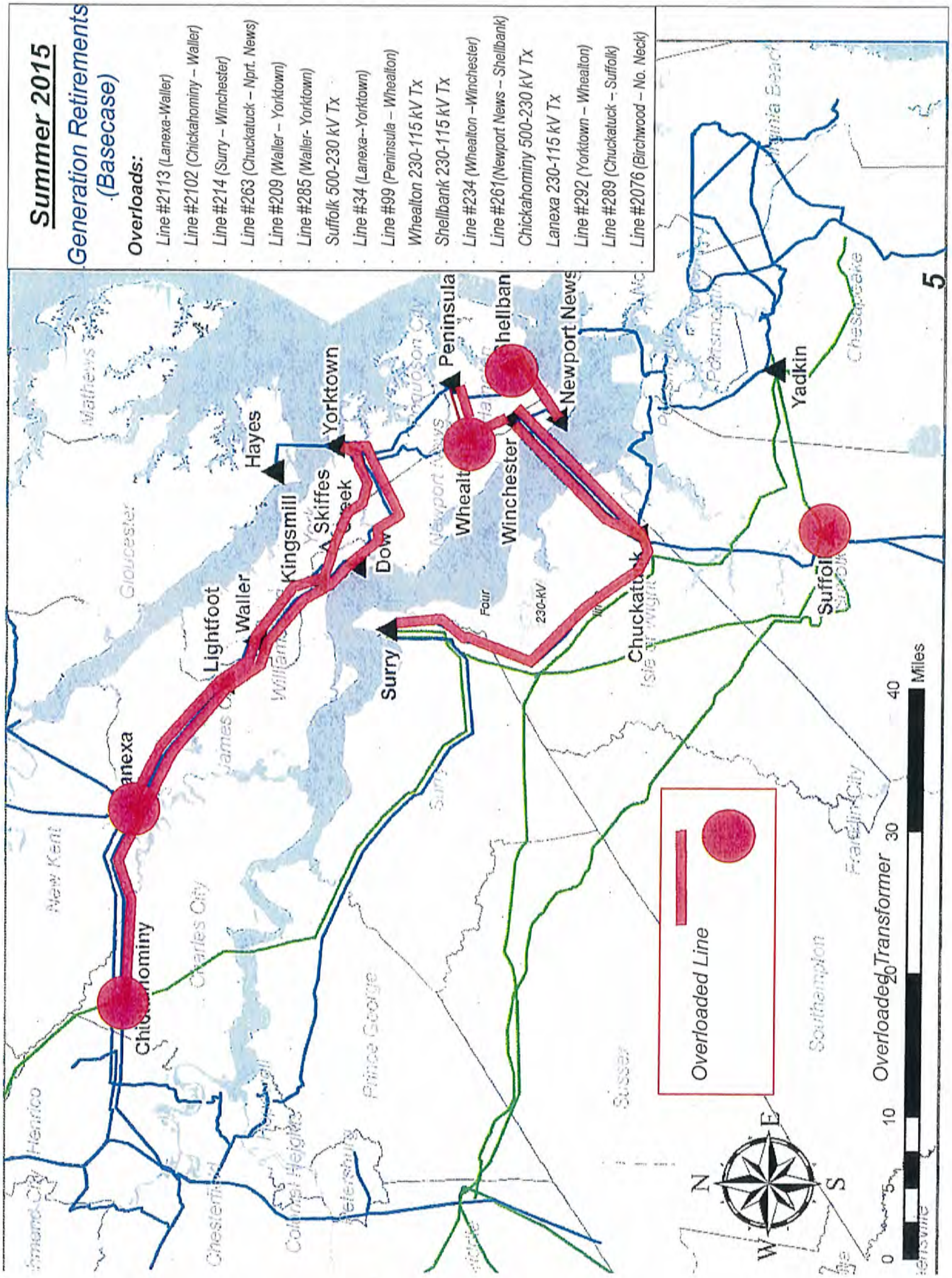
- **Alternative A** – Hybrid Single Circuit 230 kV UG Line based on 1000 MVA Plus Generation
- **Alternative B** – Hybrid Double Circuit 230 kV UG Line based on 1000 MVA/circuit Plus Generation
- **Alternative C** - Rebuild of Lines #214 and #263 Plus Generation
- **Stand Alone Generation** – Add generation to Yorktown

Dominion

Assumptions

- Consistent with Hearing Examiner's January 30 Ruling as set forth in Rebuttal Schedule 2 of Company Witness Nedwick's Rebuttal Testimony

Dominion


Summary 2015
Generation Retirements
(Basecase)
Overloads:
Line #2113 (Lanexa-Waller)
Line #2102 (Chickahominy – Waller)
Line #214 (Surry – Winchester)
Line #263 (Chuckatuck – Nprt. News)
Line #209 (Waller – Yorktown)
Line #285 (Waller- Yorktown)
Suffolk 500-230 kV Tx
Line #34 (Lanexa-Yorktown)
Line #99 (Peninsula – Whealton)
Whealton 230-115 kV Tx
Shellbank 230-115 kV Tx
Line #234 (Whealton –Winchester)
Line #261(Newport News – Shellbank)
Chickahominy 500-230 kV Tx
Lanexa 230-115 kV Tx
Line #292 (Yorktown – Whealton)
Line #289 (Chuckatuck – Suffolk)
Line #2076 (Birchwood – No. Neck)
Yorktown
Hayes
Kingsmill
Skiffes
Waller
Lightfoot
Lanexa
Surry
Peninsula
Winchester
Newport News
Chuckatuck
Suffolk
Yadkin
Overloaded Line
Overloaded Transformer
0 5 10 20 30 40 Miles
N
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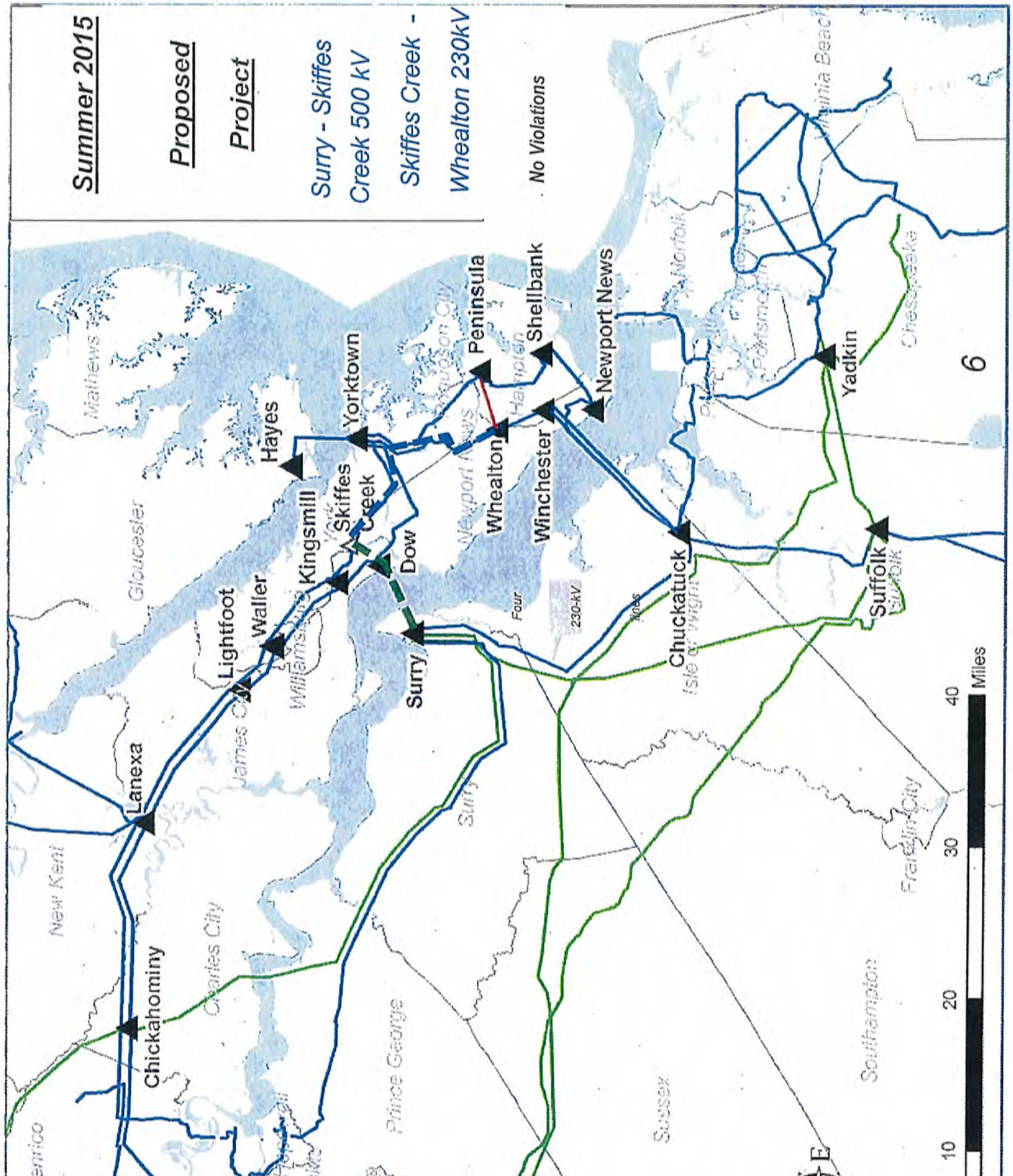
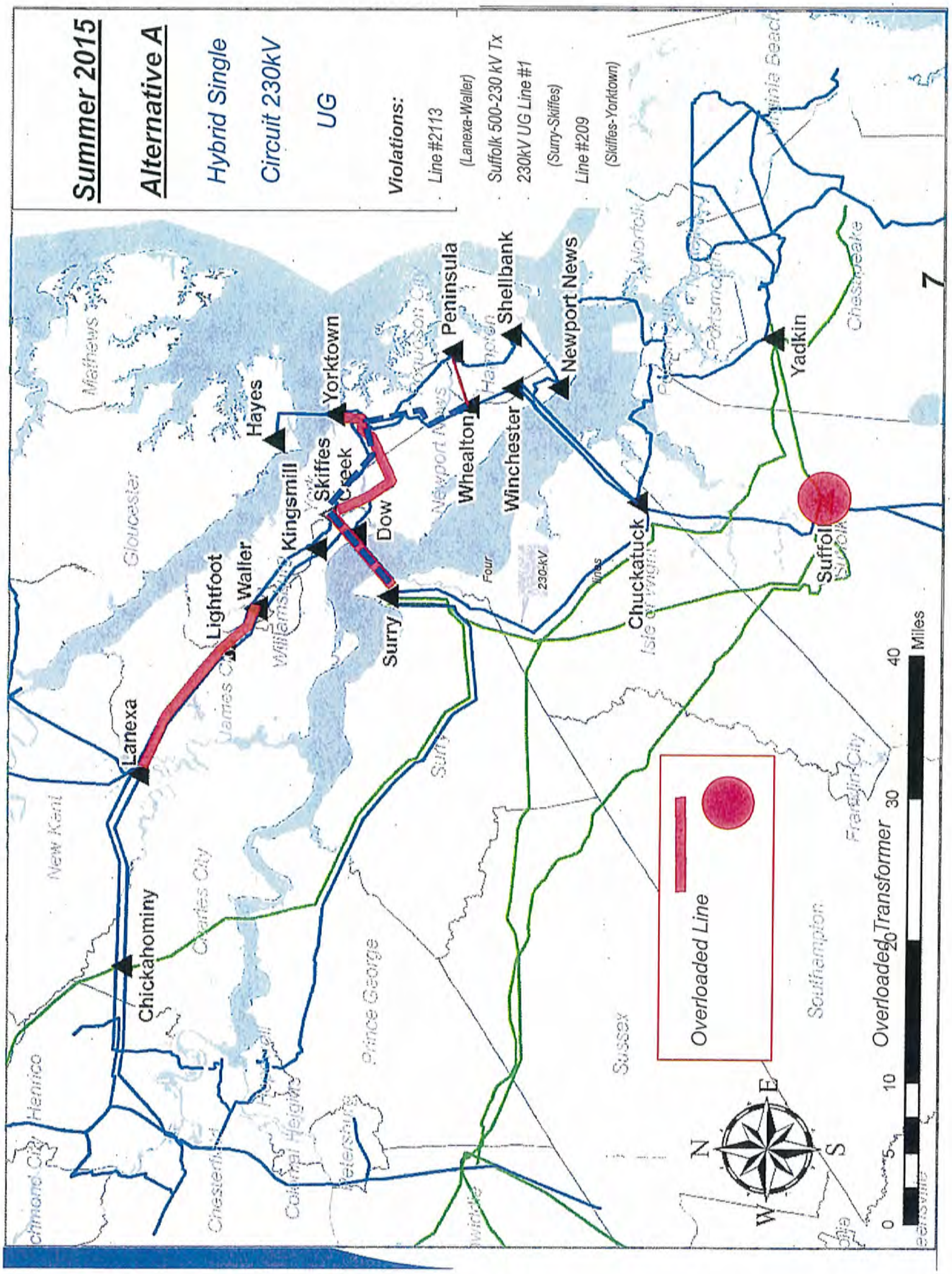
Attachment 2

Company Exhibit No. __
Witness: PN
Rebuttal Schedule 4



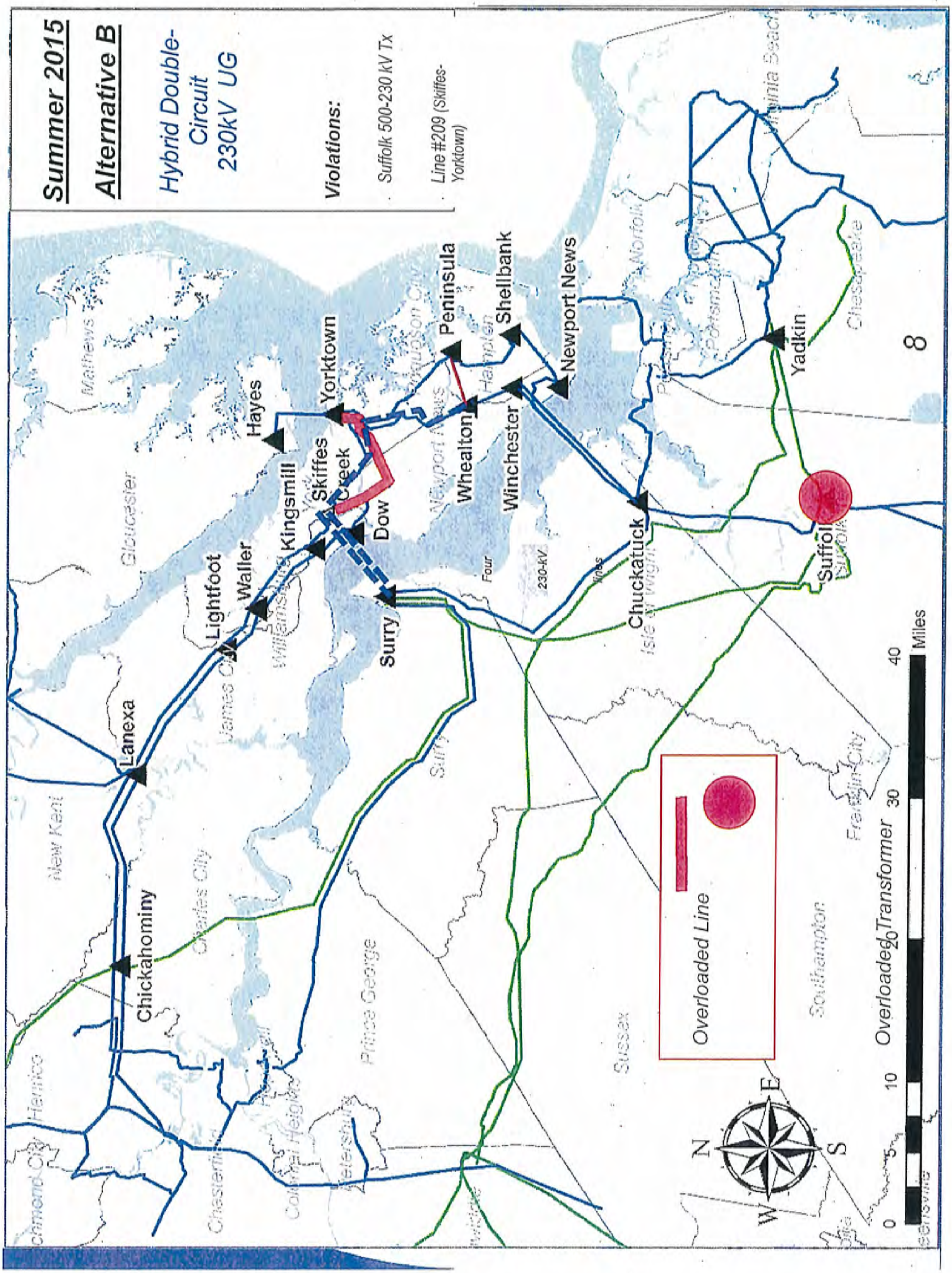
Attachment 2

Company Exhibit No. __
Witness: PN
Rebuttal Schedule 4
Page 7 of 25



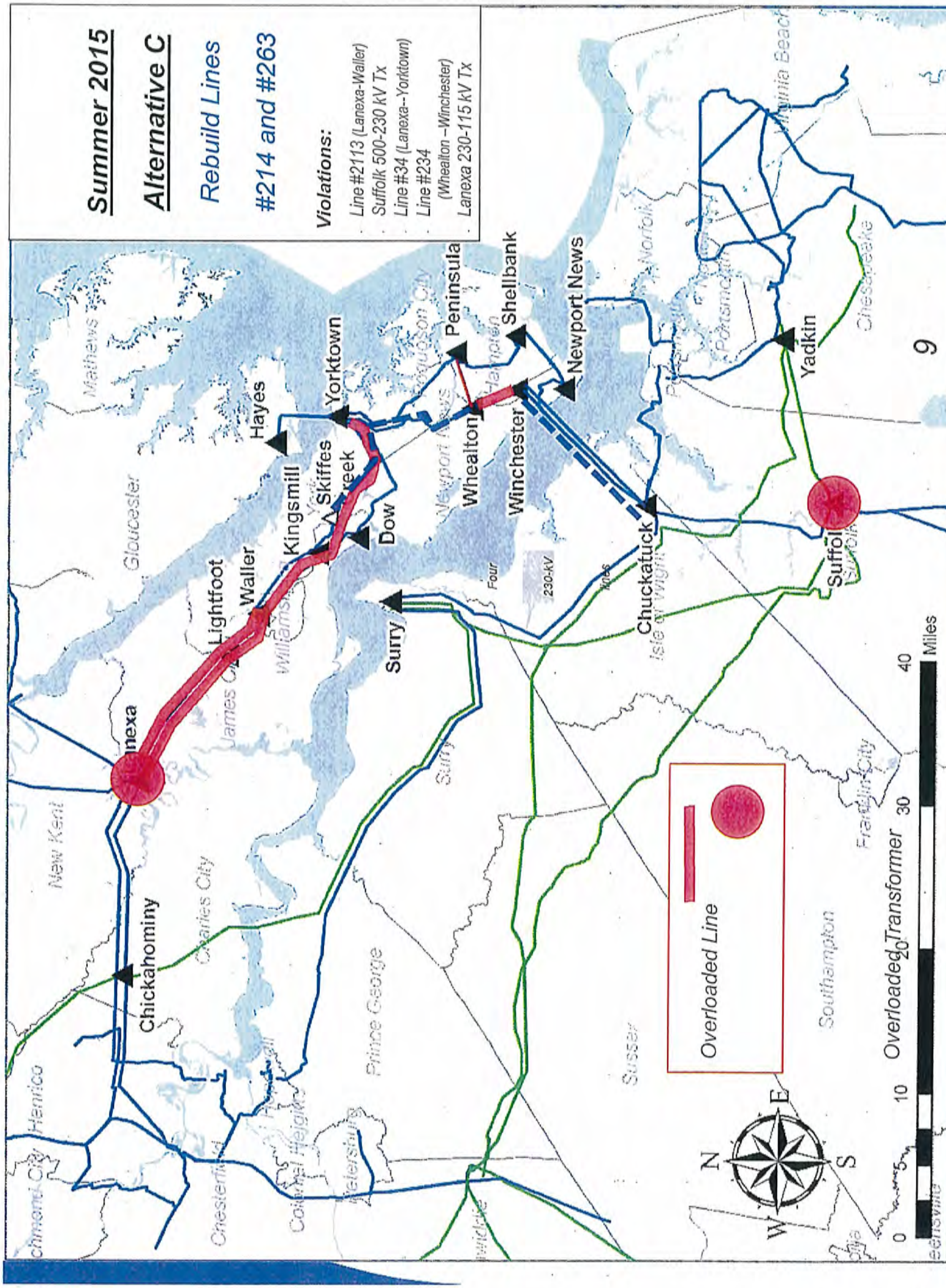
Attachment 2

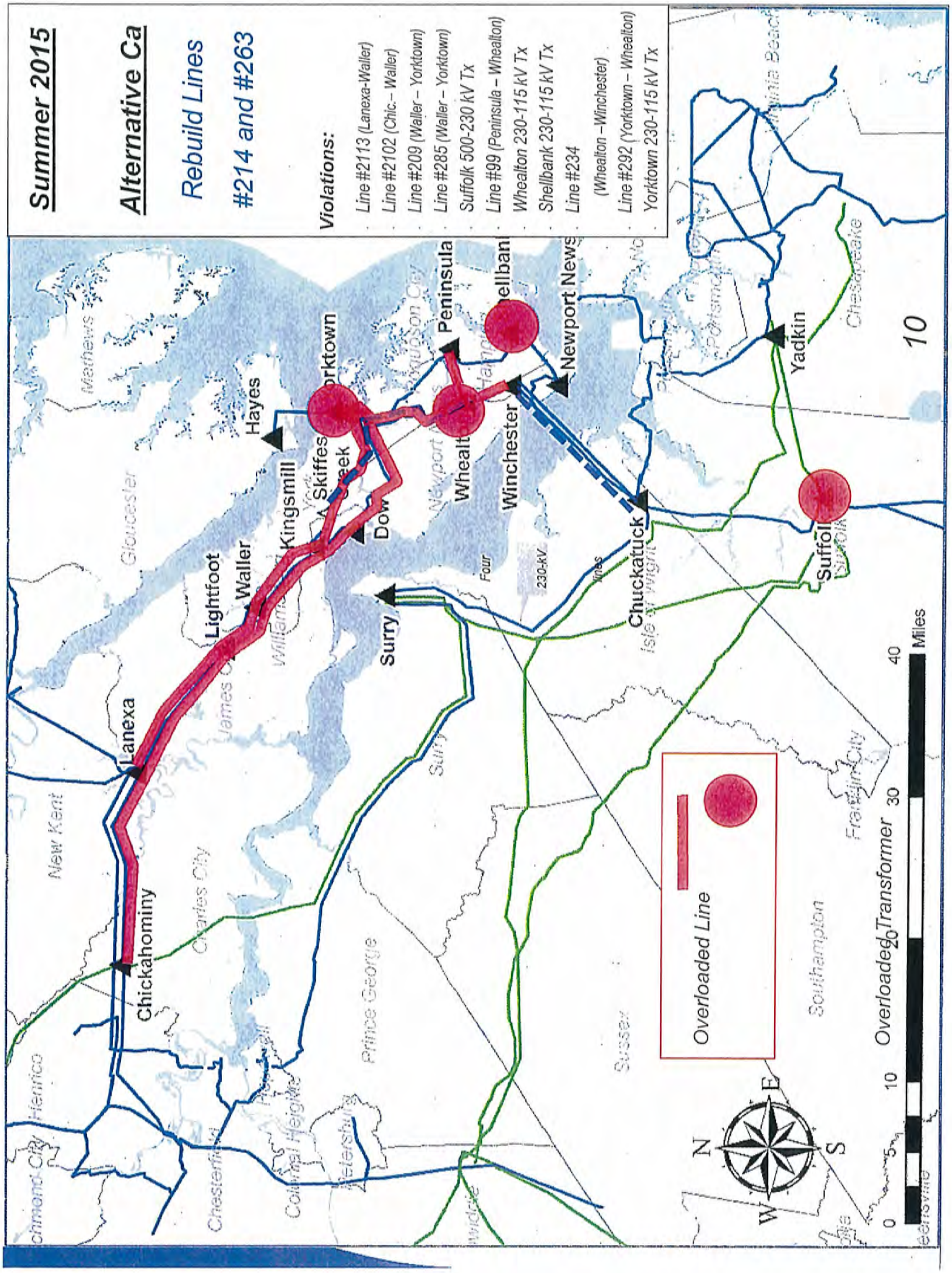
Company Exhibit No. __
Witness: PN
Rebuttal Schedule 4
Page 8 of 25



Attachment 2

Company Exhibit No. __
Witness: PN
Rebuttal Schedule 4
Page 9 of 25




Summer 2015
Alternative Ca
Rebuild Lines
#214 and #263
Violations:
Line #2113 (Lanexa-Waller)
Line #2102 (Chic.– Waller)
Line #209 (Waller – Yorktown)
Line #285 (Waller – Yorktown)
Suffolk 500-230 kV Tx
Line #99 (Peninsula – Whealton)
Whealton 230-115 kV Tx
Shellbank 230-115 kV Tx
Line #234
(Whealton – Winchester)
Line #292 (Yorktown – Whealton)
Yorktown 230-115 kV Tx
Chickahominy
Lanexa
Lightfoot
Waller
Kingsmill
Skiffes
Hayes
Surry
Chuckatuck
Winchester
Newport News
Peninsula
Yadkin
Suffolk
Overloaded Line
Overloaded Transformer
0
10
20
30
40
Miles
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S
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W

Summary of Transmission Violations[1]

Deficiency	Basecase	Alternate A	Alternate B	Alternate C	Alternate Ca	Proposed Project
Line # 2113 (Lanexa-Waller)	Yes	Yes		Yes	Yes	
Line 2102 (Chickahominy – Waller)	Yes			Yes	Yes	
Line #214 (Surry – Winchester)	Yes					
Line #263 (Chuckatuk – Newport News)	Yes					
Line #209 (Waller-Yorktown)	Yes			Yes	Yes	
Line #285 (Waller- Yorktown)	Yes				Yes	
Suffolk 500-230 kV Tx	Yes	Yes	Yes	Yes	Yes	
230 kV UG Line #1 (Surry - Skiffes)		Yes				

1. "Yes" means one or more NERC Reliability Violations in 2015 and/or 2021

Dominion

Summary of Transmission Violations[1]

Deficiency	Basecase	Alternate A	Alternate B	Alternate C	Alternate Ca	Proposed Project
Line # 34 (Lanexa--Yorktown)	Yes			Yes		
Line # 58 (Lanexa--Yorktown)	Yes			Yes		
Line #209(Skiffes – Yorktown)		Yes	Yes			
Line #34(Skiffes –Yorktown)			Yes			
Line #99 (Peninsula – Whealton)	Yes			Yes	Yes	Yes
Whealton 230-115 kV Tx	Yes	Yes	Yes	Yes	Yes	
Shellbank 230-115 kV Tx	Yes			Yes	Yes	
Line #234 (Whealton –Winchesters)	Yes			Yes	Yes	
Line #261(Newport News – Shellbank)	Yes					

1. "Yes" means one or more NERC Reliability Violations in 2015 and/or 2021

Dominion

Summary of Transmission Violations[1]

Deficiency	Basecase	Alternate A	Alternate B	Alternate C	Alternate Ca	Proposed Project
Chickahominy 500-230 kV Tx	Yes					
Lanexa 230-115 kV Tx	Yes			Yes		
Line #292 (Yorktown – Whealton)	Yes				Yes	
Line #289 (Chuckatuk – Suffolk)	Yes					
Line #2076 (Birchwood – Northern Neck)	Yes					
Yorktown 230-115 kV Tx					Yes	
Skiffes Creek 230 kV SVC				Yes		

1. "Yes" means one or more NERC Reliability Violations in 2015 and/or 2021

Dominion

Basecase: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	1	No CSC	0	39	350	21
2015	2	SU2	0	62	N/A	N/A
2015	5	SU1	1	93	N/A	N/A
2021	8	No CSC	0	55	559	43
2021	9	SU2	0	49	N/A	N/A
2021	12	SU1	0	184	N/A	N/A

Dominion

Proposed Project: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	3	No CSC	0	0	0	0
2015	4	SU2	0	0	N/A	N/A
2021	10	No CSC	0	0	2	0
2021	11	SU2	0	0	N/A	N/A

Alternative A: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	6A	No CSC	0	0	9	3
2015	7A	SU1	0	3	N/A	N/A
2021	13A	No CSC	0	9	113	7
2021	14A	SU1	0	1	N/A	N/A

Dominion

Alternative B: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	6B	No CSC	0	1	4	0
2015	7B	SU1	0	2	N/A	N/A
2021	13B	No CSC	0	1	12	0
2021	14B	SU1	0	0	N/A	N/A

Dominion

Alternative C: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	6C	No CSC	0	5	122	8
2015	7C	SU1	0	70	N/A	N/A
2021	13C	No CSC	0	12	182	13
2021	14C	SU1	0	39	N/A	N/A

Dominion

Alternative Ca – Rebuild of Line #214 and #263 (Open L 34 & 58 System Reconfiguration): Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	6Ca	No CSC	0	3	84	8
2015	7Ca	SU1	0	5	N/A	N/A
2021	13Ca	No CSC	0	10	149	13
2021	14Ca	SU1	0	4	N/A	N/A

Dominion

230 kV Alternative A + Generation: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	17A	No CSC	0	0	0	0
2015	18A	SU1	0	0	N/A	N/A
2021	21A	No CSC	0	0	0	0
2021	22A	SU1	0	0	N/A	N/A

Alternative requires 1,008 MW in 2015 and 1,449 MW (2 units min, 1 unit ≥ 87 MW) in 2021

Dominion

230 kV Alternative B + Generation: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	17B	No CSC	0	0	0	0
2015	18B	SU1	0	0	N/A	N/A
2021	21B	No CSC	0	0	0	0
2021	22B	SU1	0	0	N/A	N/A

Alternative requires 159 MW in 2015 and 551 MW (2 units min, 1 unit ≥ 27 MW) in 2021

Dominion

230 kV Alternative C + Generation: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2015	17C	No CSC	0	0	0	0
2015	18C	SU1	0	0	N/A	N/A
2021	21C	No CSC	0	0	0	0
2021	22C	SU1	0	0	N/A	N/A

Alternative requires 552 MW (2 units min, 1 unit ≥ 56 MW) in 2015 and 505 MW (2 units min, 1 unit ≥ 139 MW) in 2021

Dominion

Stand-Alone Generation Option: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	**B** (N-1)	**C** (N-1-1 & Tower Line)	**D**
2015	15	No CSC	0	0	0	0
2015	16	SU1	0	0	N/A	N/A
2021	19	No CSC	0	0	0	0
2021	20	SU1	0	0	N/A	N/A

Alternative requires 620 MW (2 units min; lose 1 unit & maintain ≥ 295 MW) in 2015 and ~~620~~ 618 MW (2 units min; lose 1 unit & maintain ≥ 295 MW) in 2021

corrected by Hearing Examiner

Dominion

Proposed Project Without Retirements: Number of Thermal Violations

Study Year	Study #	Critical System Condition	NERC TPL Category Tests			
			A (N-0)	B (N-1)	C (N-1-1 & Tower Line)	D
2021	23	No CSC	0	0	2	11
2021	24/24a	SU2/Y2	0	4	N/A	N/A
2021	25	No CSC	0	0	0	0
2021	26/26a	SU2/Y2	0	0	N/A	N/A

Dominion

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Attachment 2 Ex. 91

Revised April 8, 2013

Company Exhibit No. 91
Witness: PN
Rebuttal Schedule 5

CASE NO. PUE-2012-00029
COMPARISON OF ELECTRICAL ALTERNATIVES
($ Millions in 2012 Dollars)

			Alternative A 230 kV[1]		Alternative B 230 kV[2]		Alternative C 230 kV[3]		
2015	Proposed 500 kV	Alternative 500 kV	Transmission Only	Transmission Plus Generation	Transmission Only	Transmission Plus Generation	Transmission Only[5]	Transmission Plus Generation	Stand-Alone Option[4]
Line to Skiffes Creek	61.1	115.5	187.5	187.5	343.8	343.8	N/A	N/A	N/A
Skiffes Station	43.8	43.8	23.5	23.5	24.8	24.8	N/A	N/A	N/A
Surry Station/Chickahominy Station	1.7	5.0	14.0	14.0	23.0	23.0	N/A	N/A	N/A
Skiffes Creek-Whealton Line	46.4	46.4	46.4	46.4	46.4	46.4	N/A	N/A	N/A
Whealton Substation	2.0	2.0	2.0	2.0	2.0	2.0	N/A	N/A	N/A
Other Substations	0.4	0.5	0.4	0.4	0.4	0.4	N/A	N/A	N/A
Generation Cost	N/A	N/A	N/A	350.0	N/A	100.0	N/A	350.0	633.0
Cost Subtotal	155.4	213.2	273.8	623.8	440.4	540.4	144.8	494.8	633.0
Additional Cost for Full Compliance	0.0	0.0	214.8	0.0	48.2	0.0	82.1	0.0	0.0
Total Cost	**155.4**	**213.2**	**488.6**	**623.8**	**488.6**	**540.4**	**226.9**	**494.8**	**633.0**
2021	Proposed 500 kV	Alternative 500 kV	Transmission Only	Transmission Plus Generation	Transmission Only	Transmission Plus Generation	Transmission Only[5]	Transmission Plus Generation	Stand-Alone Y.T. Generation
Additional Cost for Full Compliance	17.3	17.3	26.7	577.0	26.7	577.0	181.9	577.0	712.0
Total Cost	**172.7**	**230.5**	**515.3**	**1,200.8**	**515.3**	**1,117.4**	**408.8**	**1,071.8**	**1,345.0**

Notes

1. Alt. A: underground 230 kV hybrid single circuit (1000 MVA) on James River Crossing Variation 3 Hybrid Conceptual Route.
2. Alt. B: underground 230 kV hybrid double circuit (1000 MVA/circuit) on James River Crossing Variation 3 Hybrid Conceptual Route.
3. Alt. C: rebuild of the existing James River crossing of 230 kV Line #214 and 230 kV Line #263.
4. Amount of generation at Yorktown that is the "lowest" cost to solve the need. 620 MW in 2015 and 2021 (2 units minimum; lose 1 unit and maintain ≥ 295 MW).
5. Alternative C is not constructable without generation already in place to address reliability issues that result from the wreck and rebuild of existing lines.
   - Generation required to be in place to support construction would cost between $383M - $652M.
   - To construct the facilities needed to address NERC Reliability Violations in 2015 would take 10 years. Additional construction time would be needed to address 2021 NERC Reliability Violations.

record.)

HEARING EXAMINER SKIRPAN: And that is Richard Schreiber?

MR. ROGERS: Yes, sir.

HEARING EXAMINER SKIRPAN: It's in.

MR. ROUSSY: Your Honor, if you'd like, the Staff is willing to go forward and begin our case with Mr. Chiles.

We would ask just for a brief ten-minute break, if that's okay.

HEARING EXAMINER SKIRPAN: We'll take 15.

(Break in proceedings.)

MR. ROUSSY: Your Honor, Staff calls John Chiles.

JOHN CHILES

was sworn and testified as follows:

E X A M I N A T I O N

BY MR. ROUSSY:

Q. Please state your name, the company you work with, and your business address for the record.

A. My name is John Chiles. I'm employed at GDS Associates. Our business address is 1850

MR. ROUSSY: Thank you, Your Honor.

BY MR. ROUSSY:

Q. On whose behalf are you testifying today, Mr. Chiles?

A. I am testifying on behalf of the Staff of the Virginia State Corporation Commission.

Q. Mr. Chiles, have you reviewed the testimony and exhibits filed by the Company after the submission of your prefiled testimony as well as testimony provided in exhibits that have been introduced up to this point in the evidentiary proceeding?

A. Yes, I have.

Q. Do you have any comments on those subsequent testimonies and exhibits?

A. I do. Most of my comments are related to the additional analysis of the project directed by the Hearing Examiner and an additional scenario that was not part of the 45 cases that the Company provided as part of that filing.

I reviewed the power flow models that support Company's additional analysis, and GDS Staff and I ran those power flow models, and based on all those efforts I've opinion able to verify the Company's results.

Q. What do you mean by verify, Mr. Chiles?

A. GDS's verification process began with the review of the power flow models to be sure that the assumptions identified in the case list were reflected in the models.

This includes the status of the pre-project work and the online status of any critical system condition generators. We checked the monitored element files to make sure that the set of monitored elements was the same in all cases.

We checked the contingency files for consistency with the Dominion Virginia Transmission Planning criteria regarding Category B, Category C, Category C tower line, and Category D contingencies.

Our final step in the verification process was to compare the thermal and voltage violations identified in the Company's power flow studies and described in Mr. Nedwick's rebuttal testimony against the violations identified in the comparable GDS power flow studies. We found an acceptable match of results and conclusions, thus verifying the Company's work.

Q. Before we get to the generation

analysis, what transmission scenarios did you analyze?

A. We analyzed four transmission scenarios from the additional analysis. These are the Surry to Skiffes Creek 500 kV overhead, which for purposes of my surrebuttal I will refer to that as the project. The Surry-Skiffes Creek 230 kV hybrid single circuit, which I'll referral to as Alternative A, which has a rating of 1000 MVA. The Surry-Skiffes Creek hybrid double circuit, which I will refer to Alternative B, which has a total rating of 2000 MVA. And to rebuild to a higher capacity the existing James River crossing double-circuit 230 kV line, which carries circuits Number 214 and Number 263 or Alternative C.

It should be noted that all the scenarios, it's assumed that the Skiffes Creek station and the Skiffes to Whealton 230 kV line are to be built as proposed.

In Alternatives A, B and C, the Skiffes Creek station only has 230 and a 115 kV bus levels, since there are no 500 kV facilities included from the Surry station in those analyses.

Q. What are the results of your transmission analysis of the project?

A. With respect to the thermal loading of voltage deviations the results of GDS's analysis reasonably matched the Company's results, thus verifying the Company results.

The project resolved all of the NERC violations identified in the base case except for the overload on line number 99 which is the peninsula to Whealton 230 kV line, in the year 2021.

Q. Did you also conduct an analysis of the Chickahominy alternative which was not a part of the additional analysis but rather was presented in the Company's application as an alternative to the 500 kV proposed line?

A. I did. I and my staff subjected the Chickahominy alternative to the same GDS verification process and found that it performed comparably to the project, which agrees with the Company's assertion.

From a transmission standpoint, I agree with the statement in Company witness Nedwick's rebuttal testimony that the 500 kV Chickahominy alternative is a functional equivalent of the project.

Q. What were your study results for the

three 230 kV options, which are Alternative A, Alternative B, and Alternative C?

A. Alternative A, Alternative B, and Alternative C were studied for the years 2015 and 2021 and evaluated with generation online or with the unavailability of the Surry Unit 1 as the critical system condition, which is consistent with the Dominion planning criteria.

Additionally, we conducted a transfer analysis to determine the minimum generation that must be located and operating on the peninsula to assure bulk power reliability there for the base case and Surry 1 critical system condition cases for both the study years of 2015 and 2021.

I compared the thermal loading high-voltage and low-voltage deviations for the analysis without the generation alternatives conducted by GDS to the Company analysis, and I was able to verify the Company results.

The thermal loading and voltage conditions identified in the Company analysis were consistent with the thermal loading and voltage conditions that I had independently identified.

Q. Can you please compare Alternative A to the project?

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A. Yes. We confirmed the information filed by Mr. Nedwick which identified the loading issue on the Surry-Skiffes Creek 230 kV circuit as well as overloads on Line 213 -- 2113, pardon me, which is the Lanexa to Waller 230 kV, Line 209, the Skiffes to Yorktown 230 kV, and the Suffolk 500 to 230 transformer.

Q. Can you please compare Alternative B to the project?

A. Yes. The Yorktown Skiffes 230 kV circuit was overloaded for the loss to the Denby Skiffes 230 kV line. And we also showed contingency loadings on Line 209, which is the Skiffes to Yorktown 230 and the Suffolk 500, 230 transformer.

Q. Can you please compare Alternative C to the project?

A. Yes. Our studies showed these loading issues that Mr. Nedwick had identified in his rebuttal, which are on Line 2113, Line 34, which we previously described as Lanexa to Yorktown 115 kV, Line 234, which is the Whealton to Winchester 115 kV, and the Suffolk 500, 230 transformer.

Q. Mr. Chiles, I've just ask you to compare Alternatives A, B and C to the project,

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and you provided a list of projected reliability criteria violations.

Are those violations that you've listed ones that are present in Alternative A but not present in the project? And similarly, are those violations one that you've identified ones that occur with Project B but not in the project? And finally, are the ones that you've listed the violations that occur in Project C -- I mean, Alternative C but not the project?

A. That's correct.

Q. Thank you for that clarification. And how would you rank these three 230 kV options?

A. Of the 230 kV options, Alternative B appears to be the most feasible, followed by Alternative A, and lastly Alternative C.

Q. Turning to the generation alternatives, please describe the methodology for the transfer studies that GDS performed.

A. Sure. The peninsula is a generation deficient load area, and it's going to be even more so following the Yorktown retirements. Thus, the peninsula depends heavily on imported power.

GDS performed transfer studies to quantify the ability of the transmission system to import power to the peninsula under the three scenarios of the 230 kV alternatives. Our goal was to determine from a power transfer perspective which one of those alternatives was best.

GDS performed this analysis using the PSS MUST software, which is a tool that's widely used in the industry. The starting point for our transfer study methodology was to assume that 804 megawatts of peninsula generation was located at the Yorktown power station site. This was a natural choice since that capacity of Yorktown Unit 3 which will be the only remaining unit -- only remaining on peninsula generation unit online following the retirement of Yorktown Units 1 and 2.

For each of the 230 alternatives, a series of single contingency power flow studies was conducted in with the output of Yorktown 3 was decremented while equally incrementing the output of Yorktown generation off the peninsula.

This process was halted at the decrement where the first volt power thermal or voltage violation occurred, otherwise known as the transfer limit.

The difference in the interim 4

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megawatt and the decrement of the output of Yorktown 3 at that transfer limit point equals the incremental import power capability under that contingency condition.

We refer to this as the first contingency incremental transfer capability or FCITC. And the FCITC was determined for the three alternatives which was the bases is for how much generation could be installed on the peninsula.

By subtracting the FCITC from the base generation online at Yorktown, the minimum generation requirement in the peninsula can be determined. If the transfer level is more than the base generation amount, then no generation is required to be online.

However, if that transfer limit is less than the base generation at Yorktown, this indicates a minimum level of online generation required.

And the transfer levels identified by the Company in the alternative analysis that was provided are consistent with results that I produced by conducting the same type of analysis.

Q. Mr. Chiles, there was one point in your last answer where you talked about decrementing the proxy generation at Yorktown while increasing the generation at Yorktown.

Did you mean to say that?

A. No. Actually, what we're doing is we are decrementing generation at Yorktown. We're increasing generation outside the peninsula as a proxy for external generation to force the power transfer into the region.

Q. Thank you. You earlier referenced that you studied an alternative that was not filed as part of Dominion's additional analysis.

Can you please elaborate?

A. Yes. My understanding is that there is a proposed generating facility in Brunswick County, Virginia which is the subject of a separate Commission proceeding.

Although I don't have any opinion on whether that facility is to be approved by Commission Staff and if so when it might be constructed, I wanted to assess the impact of that additional power generation on the need for the project.

In the 2021 power flow models provided by the Company, the Brunswick generation is in the model but not active.

We chose to increase the generation output at that location to the maximum model capability of 1300 megawatts and perform the same contingency analysis as conducted on the other alternatives.

Our findings showed that this generation will not impact the need for the project, and I've prepared a short handout of those results.

MR. ROUSSY: Your Honor, I'd like to circulate at this time a summary of Mr. Chiles' analysis on the Brunswick facility and ask that it be marked as an exhibit.

HEARING EXAMINER SKIRPAN: I'll mark this as Exhibit Number 81.

(Exhibit Number 81 is placed in the record.)

MR. ROUSSY: Thank you, Your Honor.

BY MR. ROUSSY:

Q. Mr. Chiles, do you have Exhibit 81?

A. Yes, I do.

Q. Can you just briefly describe what it is?

A. Sure. Exhibit 81 is a three-page summary of the power flow analysis that I just described. This includes the tables related to the thermal -- identified thermal violations in the region, looking at two different scenarios.

One is the Alternative B scenario with no generation on at Brunswick. We ran two other scenarios. One was a 345-megawatt scenario which was the level of which the generation was set in the model, although not active. We ran another case with the generation at the 1300-megawatt level that I described, and then we ran one scenario which kept in place only the Skiffes to Whealton facility and eliminated the river crossing. And the results you have here are the summary of those power flow results.

MR. ROUSSY: Your Honor, I would ask if this exhibit could be moved into the record.

HEARING EXAMINER SKIRPAN: Hearing no objections, it's in.

MR. ROUSSY: And, your Honor, we also have -- like James City County, we have come with a disc that we're prepared to offer into the record. I don't know whether you've ruled on James City County's disc or not, but we're fully prepared to offer that into the record and share it with the Company and whoever else may want it.

HEARING EXAMINER SKIRPAN: I entered that into the record.

MR. ROUSSY: Okay. Then I'd like to move one additional exhibit into the record. I would ask if the disc I'm about to circulate be marked as Exhibit Number 82, please.

HEARING EXAMINER SKIRPAN: I will mark it as 82. And it's in.

(Exhibit Number 82 is placed in the record.)

MR. ROUSSY: Thank you. Your Honor, just for clarification, what's on that disc is not something that most people can open and actually use because of the type of file it is, but we have given copies to the Bailiff, and also I believe one has reached -- one has reached Dominion, and James City County has one, as well.

If other parties do want a copy of the disc, by all means we are willing to make additional copies, so just let us know.

BY MR. ROUSSY:

Q. Mr. Chiles, after reviewing all the power flow cases that you have analyzed, what are your conclusions?

A. First, the project, I resolved every NERC violation that I identified within the peninsula for the 2015 area and left only one unresolved for 2021. That was line cap?Number 99 that I mentioned previously. And the Chickahominy alternative performed similarly to the project as proposed.

Secondly, the 230 kV alternatives, Alternatives A, B and C do not alone resolve all the NERC violations identified in 2015 and 2021. In between that, additional transmission facilities would need to be constructed to achieve the same reliability benefits as the project.

Third, by 2021 additional generation units will need to be installed on the peninsula if no transmission facilities were constructed. Ultimately, we believe that would be two 800-megawatt class facilities to cover the contingency lost of one of those units.

Q. Mr. Chiles, what other considerations need to be addressed in this analysis, aside from equivalent reliability impacts?

A. I recognize that the comprehensive power flow analysis provides several data points in the Commission's ultimate decision. The technical analysis in this case supports the finding that there are NERC reliability violations that must be addressed in the 2015 and 2021 periods. The project achieves this goal with a minimal need for future transmission upgrades between 2015 and 2021. The 230 kV alternatives can all achieve the same level of reliability, but the cost will be higher in terms of the initial investment.

Certainly it tying to another issue, there's a question that's been raised here about whether the generation or supplemental transmission facilities required by the alternative options can be in place in time to meet the NERC reliability requirements.

In addition, there are environmental and aesthetics impacts which Staff witness McCoy can address.

Q. Do you have a recommendation regarding the Company's application, Mr. Chiles?

A. Yes. From a transmission standpoint, I recommend the proposed project since it satisfies almost all the identified NERC violations and does so as a lower cost than any of the other options.

MR. ROUSSY: Your Honor, Mr. Chiles is available for cross-examination.

MR. QUINAN: No questions.

MS. NAVARRO: I do have some questions.

HEARING EXAMINER SKIRPAN: Any other attorneys have questions?

Okay. You're up.

EXAMINATION

BY MS. NAVARRO:

Q. Hello, Mr. Chiles. My name is Angela Navarro. I represent the environmental respondents. I have a couple of questions for you.

First, I want to talk about the retirement analysis that you performed, specifically your Exhibit 3, which is the generation retirement analysis. I know that there is a confidential version of that exhibit, and I will try my best not to go into any of the confidential information. I don't think it's necessary in order to resolve some of these questions.

A. Okay.

Q. So in that exhibit, this generation

prior to the Hearing Examiner meeting in January, so this does not relate to that.

Q. At the bottom of that same page, you talked about the approximate 5000 MVA capacity afforded by the project. That's in Line 19 and 20. Do you see that?

A. Yes, sir.

Q. Is that required to solve the NERC problem, 5000 MVA?

A. I believe if you go down to Line 20 where you talk about the additional capacity to address long-term lad growth in the area, so the 5000 MVA would not only address the NERC violations identified in 2015 and 2021 but would be available for future load growth in the area that would be expected.

So rather than piecemealing a solution where you have, say, a line that's loaded at 1000 MVA and you put something in that when it goes into power flow is loaded at 995, and then a year later you're building something else, the capacity of this line gives some flexibility for operations in the future and a lot of growth in the future.

Q. Okay. So this really undergirds your recommendation, not just that it solves NERC problems. Your recommendation regarding the project, not just that it solves the NERC problems, but that it solves a long-term problem far beyond 2021?

A. I think any prudent planner would look at not only solving the NERC violations as their primary concern, because we do have an obligation to do that, but to the extent there are ancillary benefits to a project, I think those need to be considered, as well.

If I have a case here where I construct a single facility versus constructing multiple facilities and that gives things such as an operational flexibility or things like that. Those are certainly other considerations that should, should be considered but our primary responsibility is the reliability of the bulk electric system. So first and foremost, we need to address that, and then if any ancillary benefits flow from that, those also should be noted.

Q. But that opinion you just expressed is really based upon a power engineering perspective and has really nothing to do with balancing that against mitigation of historic, aesthetic, visual, environmental impacts. Correct?

A. As I said, the power flow is agnostic to the historic and visual impacts, so we're looking strictly from a power flow perspective.

Q. So the Commission could easily say, well, you may be right, Mr. Chiles, but there are other countervailing things that need to be taken into account here?

A. I'm not going to speculate on what the Commission is going to do.

Q. That's fine. Thank you. On Page 38 of your direct testimony, Mr. Chiles --

MR. ROUSSY: Your Honor, if I could get a clarification on the page number.

MR. McROBERTS: Okay. I apologize. This is not Page 38.

BY MR. McROBERTS:

Q. Well, let me ask it this way. I know I saw it in here. I wrote the number down wrong. I apologize.

At some point, you're talking about -- well, I think it may be on Page 33, actually, Mr. Chiles. You're asking for more information regarding -- from the Company, and at some point -- oh, yes. At the very bottom of the page, Of the alternatives, you declared sort of the most likely to be the Alternative C to the project? Is that what you testified a few moments ago?

A. No. Actually, I believe I said that of the 230 kV options, Alternative B, which is the double-circuit 230 under the river, of the 230 options, yes.

Q. And B is the double circuit under the river?

A. Yes. Alternative A is the single circuit under the river. B is the double-circuit 230 under the river. And Alternative C was the rebuild of lines 214 and 263.

Q. I know you just heard Mr. Whittier this morning, and so you may or may not have done this, but have you formed an opinion about the likelihood of some of his variations solving some of your concerns regarding some of these alternatives?

A. Not having run the analysis, I really couldn't speak specifically about particular line overloads. Probably the closest thing that I noted is in the Alternative C analysis that we looked at.

The problem really that we see from the power flow is, as I said, because we have a set of lines coming in from the north, you know, from Chickahominy, we have a set of lines coming in from the south, the lines 214 and 263, and a source what you really see in looking at the power flow is if you lose the northern source, all the power flows to the southern source, and you see overloads on that end of the system.

Conversely, if you lose the lines on 214 and 263, you're importing the majority of the power from the north, and therefore you see overloads coming from Chickahominy at Waller, in that direction south.

So my concern with his options on the south side once again is you haven't really solved the issue of a strong source in the middle of the peninsula. Whether or not his solution would address that issue, I'm not sure, but just from what we saw in the multitude of runs we looked at, that would be a concern I would have, but we would need to conduct the power flow analysis to verify what he's proposed.

Q. Right. Well, it seems like you're talking about two different things there. One is sort of the solving the NERC violations, and the other is sort of this strong source. And I just want to talk about each one in turn.

The NERC violations, you just simply haven't looked at his analysis, so you really can't say whether they do or do not really solve the NERC problems at this point?

A. That's correct.

Q. So the other thing you said is the need for a strong source. Is that because of your, again, sort of planning perspective that over the long term it makes best sense from a power engineering perspective?

A. It's really twofold. The strong source, number one, serves basically as a surrogate, if you will, for the Yorktown generation. So it's reasonable to assume that that makes sense.

The other thing is by splitting up the 230 lines coming from Chickahominy going down further, going down to Whealton, by splitting those circuits and injecting power at that location, what we're really doing is we're sending power throughout the peninsula both north and south in that case, which is going to create a

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counterflow to resolve the generator deficiencies in the north, which is going to solve NERC violations to the north. It's also going to deal with the issues of the generation load deficiency in the south at that injection point, as well.

The problem we get into is by putting a strong source in that area, what we're really doing is lessening the generation load balance, so we're reducing flows across the northern and southern circuit sends into the system. What we're trying to approach is the NERC violation issue.

Q. I'm sorry. What did you say?

A. Which really -- that's really the basis for our assertion on the NERC violation issue, that the injection at Skiffes helps resolve that.

Q. Mr. Whittier's testimony was that a 230 directly to Whealton without the Skiffes Creek station resolves all of the NERC problems there. Do you dispute that?

A. I would say that I have not reviewed his power flow analysis to be able to make an assertion. My review of power flow models suggests and I think it's consistent with what we've seen in all three sets of analyses that we've performed, that injection into the middle of a peninsula makes logical sense from a power flow perspective in resolving the NERC violations.

Q. So, again, you're talking about involving the NERC problem. Again, the need for a strong source beyond solving a NERC problem, it certainly does. I mean, if you bring a really strong source, there's no doubt that that assists in many ways. But is the really reasoning behind it this concern over future growth?

A. I can't speak to the Company's rationale behind that --

Q. Well, I guess I'm asking your --

A. Beyond the NERC violations, and I'm asking my -- my opinion?

Q. Yes.

A. I'm trying to resolve the NERC violations. And bringing in a source into the area revolves the NERC violations. The power flow analyses of the 60 cases plus we've conducted indicates that the addition of the strong source at that location resolves the NERC violations.

Q. Right. But if there was an alternative that was available that solved the NERC violations that was not 500, that would be okay with you, or no?

A. We're looking for a solution which resolves the NERC violations, meets reliability criteria, and does it in a most efficient, cost-effective manner. I believe those are important criteria that we need to consider.

Q. Even if it doesn't end up with a strong 500 kV source in the middle of the peninsula?

A. Once again we looked at options which were not 500 kV. We looked at 230 kV coming across and if --

Q. If I can just interrupt you, I want to sort of get it to the end here. And so what my question is, is your primary role in reviewing this and your recommendation based upon the fact that the project solves the NERC violations, or is it a concern over future growth being solved by this big source in the center?

A. Thank you for the clarification. My primary role is identifying a solution which resolves the NERC violations.

MR. McROBERTS: Okay. Thank you.

Those are my questions. Thank you, Mr. Chiles.

THE WITNESS: Thank you.

Pamela F. Faggert
Chief Environmental Officer and
Vice President-Corporate Compliance

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May 15, 2014

Mr. David Paylor, Director
Virginia Department of Environmental Quality
629 East Main Street
P.O. Box 10009
Richmond, Virginia 23240

Re: Request for Extension of Mercury and Air Toxics Standards (MATS) Compliance Date Virginia Electric and Power Company (Dominion Virginia Power) - Yorktown Power Station Units 1 and 2

Dear Mr. Paylor:

On February 16, 2012, the U.S. Environmental Protection Agency (EPA) published notice of final regulations under Section 112(d) of the Clean Air Act (CAA) for new and existing coal- and oil-fired electric generating units (EGUs). The regulations, commonly referred to as the Mercury and Air Toxics Standards (MATS), establish strict emission limits for particulate matter, hydrochloric acid and mercury on a 30-day rolling average basis for existing units. The MATS limits take effect on April 16, 2015.

Dominion Virginia Power (Dominion or the Company) owns and operates a number of coal- and oil-fired EGUs in Virginia that are subject to the MATS requirements, including three units at Dominion's Yorktown Power Station in Yorktown, Virginia: coal-fired Units 1 (159 MW) and 2 (164 MW) and oil-fired Unit 3 (818 MW). To comply with MATS on the oil-fired unit, the Company plans to operate Yorktown Unit 3 under the "limited use unit" provisions. These provisions apply to a liquid oil-fired electric steam generating unit with an annual capacity factor of less than 8% of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

The coal-fired Yorktown Units 1 and 2 are not currently equipped with the necessary controls to achieve and maintain compliance with the MATS emissions limits. Dominion planned to retire both units by December 31, 2014 well in advance of the April 16, 2015 MATS compliance deadline; however, certain transmission upgrades have to be installed before the units can be retired without an adverse impact on the reliability of the electric grid. The transmission upgrades were originally anticipated to be completed prior to the summer of 2015. That timing would have permitted the retirement of Units 1 and 2 in advance of the MATS compliance deadline. Due to circumstances explained in detail below, this schedule has been delayed and is now expected to extend beyond the April 16, 2015 MATS compliance deadline. Accordingly, Dominion respectfully requests a one-year extension of the MATS compliance deadline for Yorktown Units 1 and 2, including all related performance testing, recordkeeping and reporting requirements, and all applicable compliance dates set forth in 40 CFR Part 63, Subparts UUUUU and the applicable general requirements in 40 CFR Part 63 Subpart A.

Yorktown Retirements

On November 1, 2011, Dominion submitted an initial notification of the proposed deactivation of Yorktown Unit 1 to PJM Interconnection, L.L.C. (PJM), as required by the conditions of the PJM tariffs under which it operates. A copy of that notification is enclosed as Attachment A.

PJM evaluated the impacts of the Yorktown Unit 1 retirement on the integrity of the electric grid. PJM determined that the retirement of Yorktown Unit 1 will adversely affect the reliability of the PJM transmission system absent upgrades to the Transmission System. At that time, PJM and Dominion estimated that it would take approximately three and a half years (until approximately June 2015) to complete the transmission system upgrades necessary to alleviate the identified reliability impacts. Under the then-current system conditions, PJM and Dominion determined that completing the necessary transmission upgrades by June 2015 would eliminate the need to operate Yorktown Unit 1 beyond its initially proposed December 31, 2014 retirement date for reliability reasons. A copy of PJM's analysis (dated December 14, 2011), including a listing of specific reliability impacts, is provided as Attachment B.

During 2011 and into 2012, the Company was evaluating the option of converting Yorktown Unit 2 to natural gas fuel and therefore did not include Unit 2 in the deactivation notice. However, after evaluation of the potential repowering, the Company concluded that there was not enough firm gas supply to support year-round operation of gas-fired generation at Yorktown Unit 2, and that an expansion of the gas supply could not be completed until 2018. In addition, estimated costs to expand natural gas capacity to support generation in the area were significant and would exceed the cost of the transmission alternatives. On October 9, 2012, the Company notified PJM of the planned retirement of Yorktown Unit 2 effective December 31, 2014. PJM's response to the Unit 2 retirement notification (dated November 8, 2012), provided as Attachment C, specified that the Unit 2 retirement would not adversely affect the reliability of the electric transmission system provided that Unit 2 does not retire sooner than proposed and the previously identified baseline upgrades related to the retirement of Yorktown Unit 1is completed prior to June 2015.

Skiffes Creek Transmission Project

To address projected North American Electric Reliability Corporation (NERC) violations related to the Yorktown retirements, Dominion filed with the State Corporation Commission of Virginia (Commission) on June 11, 2012, an application for approval and certification of electric transmission facilities, consisting of construction of the Surry-Skiffes Creek 500 kV transmission line, the Skiffes Creek-Whealton 230 kV transmission line, and the Skiffes Creek 500 kV-230 kV-115 kV Switching Station, and work at Dominion's existing Surry and Whealton stations (collectively, the Skiffes Creek project).[1]

In its Application, Dominion stated that electric power flow studies projected violations of mandatory NERC Reliability Standards on existing facilities to occur by the summer of 2015, and that the failure to address these projected violations could lead to loss of service and potential damage to the Company's electrical facilities in the North Hampton Roads load area.[2] During the course of the Commission proceeding, all of the load flow studies conducted by Dominion were independently verified by the Commission Staff consultant, John Chiles. Mr. Chiles determined that with the retirement of either Yorktown unit, NERC reliability violations would occur beginning in 2015.[3]

In the Commission proceeding, Dominion explained how the Skiffes Creek project would resolve all of the identified NERC Reliability Violations in 2015 and address the risk of cascading outages by (1) providing a new source of bulk power from the 500 kV system to support the 230 kV system in the North Hampton Roads load area, (2) relieving loading on that system through the addition of a new 230kV source into the Peninsula east of Skiffes Creek, and (3) feeding existing east-west 230 kV and 115 kV lines to be split to receive power from Skiffes Creek Station.

In addition to Dominion and the Commission Staff, thirteen parties participated in the Commission proceeding, including Charles City County, James City County, and landowners, collectively and individually. The Virginia Department of Environmental Quality (DEQ) provided its report on the Skiffes Creek project on August 31, 2012. There were local public hearings and an evidentiary hearing at the Commission that lasted eight days.

On November 26, 2013, the Commission issued an Order approving the Certificate of Public Convenience and Necessity (CPCN) for the Skiffes Creek project to be constructed by Dominion (Approval Order). The Approval Order is included as Attachment D. In the Approval Order, the Commission found that the record demonstrated significant reliability risks beginning as early as 2015 in the North Hampton Roads load area. The Commission further found that to address the

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[1] *Application of Virginia Electric and Power Company For Approval and Certification of Electric Facilities for the Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line and Skiffes Creek 500 kV-230 kV-115 kV Switching Station*, Case No. PUE-2002-00029, Application (Jun. 11, 2012) (hereafter, Application).

[2] The North Hampton Roads load area includes the following: (i) Charles City County, James City County, York County, Williamsburg, Yorktown, Newport News, Poquoson, and Hampton; (ii) Essex County, King William County, King and Queen County, Middlesex County, Mathews County, Gloucester County, and the City of West Point; and (iii) King George County, Westmoreland County, Northumberland County, Richmond County, Lancaster County, and the City of Colonial Beach.

[3] Approval Order at 21 (Nov. 26, 2013).

risks and maintain adequate reliability for customers, significant system upgrades are needed to serve the North Hampton Roads load area. The Commission approved all of the components of the Skiffes Creek project described above, but approved an alternative route for the 500 kV transmission line across the James River such that the line would cross the property of the James City County Economic Development Authority (EDA). Because the EDA is a unit of the County government, Dominion does not have the ability to acquire an easement across that property without agreement from the governmental entity. James City County and the EDA had represented during the evidentiary hearing that the EDA would willingly enter into such an agreement with Dominion.

Because no agreement had been executed between Dominion and the EDA, the Commission re-opened the record in an Order issued January 7, 2014 to hold a hearing to admit additional evidence on the rights that Dominion needed to construct the Skiffes Creek project across the EDA property. At that hearing, Dominion presented evidence on the schedule risks facing the project. These risks include the U.S. Army Corps of Engineers (Corps) permit process that had been initiated by Dominion in July of 2013 and the retirement of Yorktown Units 1 and 2 pursuant to MATS. On February 28, 2014, the Commission issued an Order Amending Certificates (Amending Order) to amend the Approval Order, approving the Company's proposed route for the 500 kV transmission line across the James River. The Amending Order is included as Attachment E. The basis for the Commission's amendment of the Approval Order included the Corps permit process and the importance of maintaining reliable electric service for customers in the North Hampton Roads load area, which could "no longer depend on Dominion's ability to obtain a right-of-way from the EDA" for construction of the Skiffes Creek project. The Amending Order reiterated the urgent need for the project and stated the following:

> *The Commission remains concerned about the serious reliability risks to the North Hampton Roads [Load] Area that supported, and continue to support, approval of the Certificated Project. Until the Certificated Project is placed in service to address those risks, the Commission expects Dominion to continue taking all reasonable steps to ensure reliable service is maintained in the North Hampton Roads Area. Such steps should include, but are not necessarily limited to, pursuing the limited extensions of the MATS Rule that are available to the Company and expeditiously pursuing all necessary approvals from the Army Corps.*

The Company's application for a Corps permit for the Commission-approved route is pending. Except for some limited work, the Company will not begin construction of the Skiffes Creek project until receiving a permit from the Corps. In addition, there are pending legal actions related to the Skiffes Creek project.[4]

[4] There is currently pending in James City County Circuit Court a Petition for Declaratory Judgment and Injunction for Skiffes Creek Switching Station filed by James City County on May 23, 2013. In addition, James City County and another party to the Commission proceeding have filed petitions to appeal the November 26, 2013 Commission Order and notices of participation to appeal the February 28, 2014 Commission Order Amending Certificate.

Reliability Analysis

The Company has requested an update from PJM on the analysis of the reliability impacts of the retirements given the delay of the in-service date currently anticipated for the Skiffes Creek project. That updated analysis from PJM, included as Attachment F, is consistent with the previous analysis presented in Attachments B and C in requiring the availability of Yorktown Units 1 and 2 until completion of the Skiffes Creek project, currently estimated to be completed no later than the fourth quarter of 2016.

Because the Skiffes Creek project's commercial operations date now extends past the MATS compliance date of April 16, 2015, and Yorktown Units 1 and 2 must remain available during that time for electric reliability, the Company is hereby requesting a one-year (fourth year) extension of the MATS compliance deadline (i.e., until April 16, 2016) for Yorktown Units 1 and 2.[5]

Requested Action

DEQ is authorized to grant the requested extension under Section 112(i)(3)(B) of the CAA, 42 U.S.C. § 4212(i)(3)(B), and 40 CFR § 63.6(i)(3). For tbe retiring units included in this request, deactivation and the construction of additional transmission through the Skiffes Creek project is the MATS compliance strategy.

The MATS deadline extension will provide time to complete construction of the additional transmission facilities necessary to deactivate the units without risk of triggering the reliability issues identified by PJM, and provide the flexibility to dispatch these generation assets during the outages of other units where pollution control installations or replacement generation are being constructed in order to comply with MATS and other environmental obligations. The requested extension is consistent with U.S. EPA's discussion of the range of circumstances that might trigger a need for additional time to comply in the preamble to the final MATS rule.[6]

Dominion cannot predict the timing for Corps approval of the Skiffes Creek project. Current estimated timing is based on the assumption that no National Environmental Policy Act Environmental Impact Statement (EIS) would be required. Should the Corps ultimately determine that an EIS is required, the Corps process could be lengthened by up to one year. A one year extension of the Corps process would push the in-service date for the proposed Skiffes Creek project to after April 16, 2016, thereby making it necessary for Dominion to request further time before retirement of the Yorktown units. This request may take the form of a request for a U.S. EPA Administrative Order (AO), pursuant to the process that EPA outlined in

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[5] As noted previously, this extension request includes all related performance testing, recordkeeping and reporting requirements, and all applicable compliance dates set forth in 40 CFR Part 63, Subparts UUUUU and the applicable general requirements in 40 CFR Part 63 Subpart A.

[6] See 77 *Fed. Reg.* 9410-12; February 16, 2012.

a December 16, 2011 memorandum issued by the Office of Enforcement and Compliance Assurance (OECA).[7]

The estimated construction schedule of the Skiffes Creek project also assumes that Dominion will be able to obtain from PJM timely outages of existing transmission lines required for safe construction of the project. Many outages will be required for construction of the project, which includes substantial use of existing rights-of-way occupied by existing, energized transmission lines. In addition, other delays in the transmission construction, permit delays, or further litigation could occur that may further postpone the deactivation of the coal units at Yorktown.

By requesting this one-year extension based on currently known commitments and obligations, Dominion does not waive its right to request additional time, as necessary, before the retirement of either or both of these units. Accordingly, in the event circumstances described above, or any other unforeseen circumstances, further delay the completion of the necessary project (and thereby push the retirement of either or both of the Yorktown coal units beyond April 16, 2016), the Company intends to inform EPA that the Company may need to pursue further relief, including an AO pursuant to the process discussed above.

Dominion appreciates your prompt consideration of this extension request, and Company representatives are available to meet with you and discuss this request and the enclosed supporting information, if necessary. Please contact me or Lenny Dupuis @ 804-273-3022 to arrange a meeting date or if you have any questions.

Sincerely,

Pamela F. Faggert

Pamela F. Faggert

Attachments

CC: Mr. Michael S. Dowd – Virginia DEQ
Ms. Tamera Thompson – Virginia DEQ
Ms. Patricia Buonviri – Virginia DEQ
Ms. Diana Esher – U.S. EPA Region III
Mr. Brian Rehn – U.S. EPA Region III

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[7] See EPA OECA, Memorandum: The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury And Air Toxics Standard; December 16, 2011.

**REBUTTAL TESTIMONY
OF
KURT W. SWANSON
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029**

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

A. My name is Kurt W. Swanson. I am Project Director – Regulation for the Company. My business address is 701 East Cary Street, Richmond, Virginia 23219.

Q. Have you previously provided testimony in this proceeding?

A. No, I have not.

Q. What is your educational and professional background?

A. I graduated from the University of Virginia in 1975 with a Bachelor of Arts degree in Economics and received a Master's of Business Administration degree from the University of Richmond in 1994. I was hired by Virginia Electric and Power Company in 1976. From 1976 to 1980, I worked in Commercial Operations in the Customer Service Department. In 1980, I was promoted to the position of Rate Analyst in the Company's Rate Department, and in 1983, I was promoted to Supervisor of Engineering Analysis, responsible for the preparation of the Company's load research studies. In December 1985, I was appointed Regulatory Specialist in the Rate and Load Research section of the Rate Department. Effective June 1, 2002, I was appointed to Manager – Regulatory and Pricing. On December 1, 2011, I was appointed Director – Regulation, and on January 1, 2013, I was appointed Project Director – Regulation. My current

Attachment 5

Company Exhibit No. __
Witness: KWS
Rebuttal Schedule 1
Page 1 of 1

Development of the Estimated Annual Revenue Requirements used to Estimate the Monthly Summer Bill Impacts [1]
($ Millions)

Description of Projects	(1) Beginning of Year Amount [2]	(2) Depreciation [3] (1)/ 51	(3) End of Year Amount (1)-(2)	(4) Average Amount ((1)+(3))/2	(5) Net Plant Carrying Charge without Depreciation [4]	(6) Annual Revenue Requirement (2)+((4)*(5))	(7) Regional Cost Allocation % to Dominion Zone [5]	(8) Regional Cost Allocation to Dominion Zone (6)*(7)	(9) Allocation of Annual Revenue Requirement to Va Jurisdiction [6] 72.7784% of (8)
1 Proposed Project with the 500 kV Updated Proposed Route									
500 KV Line	61.1	1.2	59.9	60.5	14.0582%	9.7	12.3800%	1.2	0.9
230 kV Line	46.4	0.9	45.5	45.9	14.0582%	7.4	99.8400%	7.4	5.4
Total Transmission Line	107.5	2.1	105.4	106.4		17.1		8.6	6.2
500 KV Substation	7.4	0.1	7.3	7.3	14.0582%	1.2	12.3800%	0.1	0.1
230 kV Substation	40.5	0.8	39.7	40.1	14.0582%	6.4	99.8400%	6.4	4.7
Total Substation	47.9	0.9	47.0	47.4		7.6		6.6	4.8
Total Project (Total Transmission Line and Substation)	155.4	3.0	152.4	153.9		24.7		15.1	11.0
2 Proposed Project - 500 kV Chickahominy Alternate Route									
500 KV Line	115.5	2.3	113.2	114.4	14.0582%	18.3	12.3800%	2.3	1.7
230 kV Line	46.4	0.9	45.5	45.9	14.0582%	7.4	99.8400%	7.4	5.4
Total Transmission Line	161.9	3.2	158.7	160.3		25.7		9.6	7.0
500 KV Substation	10.7	0.2	10.5	10.6	14.0582%	1.7	12.3800%	0.2	0.2
230 kV Substation	40.6	0.8	39.8	40.2	14.0582%	6.4	99.8400%	6.4	4.7
Total Substation	51.3	1.0	50.3	50.8		8.1		6.6	4.8
Total Project (Total Transmission Line and Substation)	213.2	4.2	209.0	211.1		33.9		16.3	11.8
3 Alternative B									
500 KV Line	0	0.0	0.0	0.0	14.0582%	0.0	12.3800%	0.0	0.0
230 kV Line	390.2	7.7	382.5	386.4	14.0582%	62.0	99.8400%	61.9	45.0
Total Transmission Line	390.2	7.7	382.5	386.4		62.0		61.9	45.0
500 KV Substation	0.0	0.0	0.0	0.0	14.0582%	0.0	12.3800%	0.0	0.0
230 kV Substation	50.2	1.0	49.2	49.7	14.0582%	8.0	99.8400%	8.0	5.8
Total Substation	50.2	1.0	49.2	49.7		8.0		8.0	5.8
Total Project For Partial Compliance (Total Transmission Line and Substation)	440.4	8.6	431.8	436.1		69.9		69.8	50.8
Additional Work Needed for Full Compliance	48.2	0.9	47.3	47.7	14.0582%	7.7	99.8400%	7.6	5.6
Total Project For Full Compliance (Total Transmission Line and Substation)	488.6	9.6	479.0	483.8		77.6		77.5	56.4

Notes:

[1] The methodology for developing the estimated annual revenue requirements is based on the methodology included in Attachment 7 of Dominion's formula rate approved by FERC.
The populated version of Dominion's 2012 Formula rate can be obtained from the PJM website (see the link below).
http://pjm.com/markets-and-operations/transmission-service/~/media/markets-ops/trans-service/20120112-virginia-electric-and-power-company-2012-formula-rate-informational-filing.ashx

[2] The Beginning of Year Amount is an estimate of the applicable project's costs.

[3] 51 years is the assumed amortization period of each project and it corresponds to the life used to determine depreciation in Attachment 7 of Dominion's formula rate.

[4] The Net Plant Carrying Charge without Depreciation is from Appendix A, (line 154) of the populated version of Dominion's 2012 formula rate - see note 1. It is based on the following cost of capital from that same Appendix A (see lines 112 - 129).

	Capitalization Ratios	Costs	Weighted Costs
Debt Cost	44.9%	5.61%	2.52%
Preferred Cost	1.8%	6.43%	0.11%
Common Cost	53.3%	11.40%	6.08%
Total Return			8.71%

[5] These allocations percentages are from Schedule 12 Appendix of the PJM Tariff, page 837.

[6] The 72.7784 % is the ratio of the Virginia jurisdictional peak demand coincident with the 2012 Network Service Peak Load of the Dominion Zone.

REBUTTAL TESTIMONY
OF
MARK S. ALLEN
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

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

A. My name is Mark S. Allen and I am Manager, Electric Transmission Line Engineering for the Company. My business address is 701 East Cary Street, Richmond, Virginia 23219.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering (*magna cum laude*) from West Virginia University of Technology in 1981. I am a Registered Professional Engineer in Connecticut, Kentucky, Michigan, Ohio, Pennsylvania, Virginia, Utah and West Virginia. I have 31 years of experience with the Company in both Transmission and Distribution. I started my career with the Company as a Project Engineer in Transmission Engineering in 1981. In 1985, I moved to Distribution Planning as a Planning Engineer in the Eastern Division and then returned to Transmission Engineering in 1989. I have experience in both overhead and underground transmission design.

Q. What are your responsibilities as Manager, Electric Transmission Line Engineering?

A. I am responsible for the coordination of all high voltage transmission designs (overhead and underground) on the Dominion Virginia Power system. This includes all new equipment, both of the Company and its customers, these lines must be temporarily taken out of service, or sufficient reactive compensation facilities must be added to the system. So operability concerns also lead us to prefer overhead transmission lines. Underground lines present significant issues for "reclosing" after faults and also can present transmission operating issues from the effects of weather.

The fourth issue considered when determining whether to build overhead or underground is cost. Dominion Virginia Power has a responsibility to build a reliable system in as cost-effective a manner as possible. As explained in detail below, both of 230 kV underground Alternatives A and B not only cannot be constructed by the need date, but would cost $333.2 million more than the $155.4 million cost of the proposed Project.

Q. What factors would cause the underground installation of a transmission line to have a detrimental effect on the reliability of electric service?

A. Outages of transmission lines, both overhead and underground, are not common but when they occur it is very important to restore the line to service as quickly as possible because of the amount of power they carry within our system and the significant numbers of customers that can be impacted.

As stated above, an outage of an overhead transmission line can usually be repaired within a matter of hours. Location of the problem is easy to identify. Our system operator will know that the outage is on a certain line between two substations, and a visual inspection of the line via air or land will quickly disclose the location where repairs are needed. We can gain access to the site promptly by road and along the right-of-way itself. We maintain our own skilled personnel, equipment and materials to make such repairs promptly, and qualified contractors are readily available, if necessary. The line can usually be restored quickly. In most outage cases, such as those caused by a broken insulator or conductor, repairs take only a few hours. In very rare cases of a structure failure, restoration can be, on average, one to three days. Based on the Company's experience with repairs required for overhead lines over water, restoration may take slightly longer depending on the nature of the problem, but still much faster than an underground repair.

In contrast, location of a failure of an underground transmission line is more difficult and time-consuming. First, each cable must be tested to identify the failed cable. Complex fault location equipment is used to calculate a distance to the fault. When the damaged section of a land-based cable is identified, the site must be excavated sufficiently to provide access to the failed cable. Depending on the nature of the damage, the cables must either be repaired with a splice, or the entire section between existing splices must be removed from its protective pipe casing and replaced. Splicing a 230 kV transmission cable is highly specialized. We must rely on the very few contractors in the United States that can do this work. After such a contractor is on-site and the damaged area has been excavated, it may take several weeks to over a month to complete the entire repair operation. If the damaged cable must be removed and a new cable installed, the process takes even longer. In the case of the Northern Virginia failure in 2004, the fault was the result of steel h-pile being driven through the steel pipe and cable. Consequently, we knew exactly where the failure was so assessment and repairs began immediately. A temporary repair had to be installed around the failed/ruptured pipe to prevent additional leakage of the dielectric fluid. The fluid that did spill had to be cleaned up in accordance with environmental regulations. One of the specialized contractors referenced above was brought in to facilitate and complete the repair. An oil freeze had to be installed on each side of the failed section so the pipe could be reopened to make the splice. A temporary splice pit had to be installed at the splice location to maintain proper atmospheric conditions while making the repair. The end result was a five-week repair of this 230 kV cable and pipe.

However, if the damaged section is deep underneath the bed of the river, in a directionally drilled pipe-type cable system, as would be the case for either of 230 kV Alternatives A or B, the repair becomes much more difficult and time-consuming. This is due to the fact that the pipe can be as much as 60 feet below the bottom of the river bed. Specialized marine construction contractors, as well as cable installation contractors, would be required to locate and fully evaluate the damage, devise a repair plan, and execute the plan.

Q. Are there additional reliability differences between underground and overhead transmission facilities?

A. Yes, with respect to "reclosing" of circuit breakers after a fault occurs. When a fault occurs on an overhead transmission line, the line may not have been damaged and can be restored to service immediately. When our overhead transmission system experiences a fault, breakers open to protect the line but automatically and immediately "reclose" so that, if the line has not been damaged, the power flow in the line is interrupted only for a fraction of a second. This can be done safely because a fault event is usually a temporary condition for an overhead line. Arcing associated with a fault of an overhead line does not usually do significant damage to the equipment.

Automatic "reclosing" is not permitted on underground transmission lines because the fault will likely result in damage to the cable and its insulation and immediate reclosing would cause more extensive damage. The resulting damage would require the lengthy repair process that I described above. Therefore, when a fault occurs on an underground transmission line, we keep the line out of service until tests can be performed to determine the cause of the fault and ascertain the extent of damage to the cable. Typically such testing would take several days to mobilize personnel and complete.

Q. What are the voltage control problems associated with underground cables and how do they affect the operation of the Company's transmission system?

A. Due to the electrical characteristics of underground cables, namely the capacitance, voltages on such cables can rise to unacceptable levels during periods of light load. These excessive voltage levels can damage equipment and create situations where devices can no longer function as required under all operating conditions.

Q. Are underground lines immune from the adverse effects of weather?

A. No. In fact, one of the 230 kV lines under the Elizabeth River locked out in 2009 for a fault during Hurricane Ida. The storm sprayed salt water into the transition station and caused the cable terminations to flashover from the salt contamination. The circuit locked out as designed and was out of service until the termination could be repaired and cleaned. It is actually standard practice now to de-energize this line during a major storm preparation to prevent flashover damage.

Q. How do the construction impacts of underground transmission lines compare to those of overhead transmission lines?

A. On land, there are significantly more impacts with underground construction compared with overhead line construction. For overhead construction, pipe pile foundations will be vibrated into the ground approximately every 1,000 feet. This results in minimal land disturbance. In contrast, for the double circuit underground alternative, two trenches, each approximately six feet wide and five feet deep will need to be excavated for the entire length of the circuit. This will result in an estimated 11,733 cubic yards of soil excavation for every mile of underground construction.

For the river crossing, the overhead construction would be similar to the land construction, with pipe pile foundations installed approximately every 1,400 feet, resulting in minimal riverbed disturbance. For the underground construction, most of the river crossing would not be disturbed, as the cable pipes would be directionally drilled underneath the riverbed. However, at every splice point for the cable, a trench approximately 900 feet long, four feet wide, and 15 feet deep would be excavated in the riverbed in order to properly "overboard" and bury the cable splices. Due to the length of the river crossing, this would have to be done three times for each individual pipe. This results in a riverbed excavation of 36,000 cubic yards of sediment and riverbed for six pipes with three splices each.

Q. Should the Commission require any portion of a Surry-Skiffes Creek line to be constructed underground?

A. No. The proposed Surry-Skiffes Creek transmission line should not be constructed underground for the following reasons:

1. As stated in the discussion above, the overall reliability of an underground transmission line is less than an equivalent overhead line due to the time it takes to locate and repair an underground fault. The duration of an underground outage has been validated by the Company's own experience with underground transmission, as in the case of the Northern Virginia project discussed above. Since customer reliability is a major concern in determining whether to build overhead or underground transmission lines, an overhead line should be constructed whenever a viable overhead route exists.

2. The Company does not consider 500 kV to be a viable underground alternative. The only 500 kV underground cables in the United States are at the Grand Coulee Dam in the state of Washington, which are short generator connections from the dam to the adjacent switchyard, and these circuits are currently in the process of being replaced due to reliability concerns. As explained by Company Witness Nedwick, neither 230 kV Alternative A nor B can, without significant further additions to the transmission system, resolve all of the identified NERC Reliability Violations, and either of these alternatives would only increase the load on the already stressed 230 kV transmission system in South Hampton Roads.

3. The Company has a responsibility to build a reliable system in as cost-effective manner as possible. My Rebuttal Schedule 4 provides the estimated overhead transmission costs for Alternatives A, B and C. As shown there, the estimated

cost for the proposed 500 kV Surry-Skiffes Creek overhead line, including Skiffes Station and work at Surry Station, is $155.4 million, while the cost for a corresponding hybrid underground/overhead double circuit 230 kV line from Surry to Skiffes Station (Alternative B) is $440.4 million, representing a 2.83 times cost differential for comparison purposes. However, this does not account for the $48.2 million of additions to the transmission system that would be required to resolve the NERC Reliability Violations for 2015 not addressed by Alternative B. When those costs are considered, the cost of Alternative B for 2015 increases to 3.14 times that of the Company's proposed overhead Surry-Skiffes Creek line. And with the additional $26.7 million of additional compliance facilities required for 2021, the cost of Alternative B is 2.98 times that for the proposed Project. The cost to construct single circuit 230 kV Alternative A would be $273.8 million, but the additions to the transmission system that would be required for that alternative to resolve the identified NERC Reliability Violations for 2015 and 2021 would be those required to build Alternative B plus the same compliance facilities as for Alternative B to resolve NERC Reliability Violations in those years. Accordingly, the total cost is the same for both Alternatives A and B.

4. The length of time to construct either transmission Alternative A or B is a minimum of 60 months after issuance of the Commission's Final Order, which would mean completion in mid to late 2018, far exceeding the required summer 2015 need date for this Project. The overhead construction of the proposed 500 kV line is projected to be completed by December 31, 2014, while the total

Project, including the 230 kV line from Skiffes Creek-Whealton, will be completed by May 31, 2015.

III. HB 1319

Q. Has the General Assembly enacted legislation that affects the choice of undergrounding versus overhead construction?

A. In 2008, the General Assembly enacted HB 1319 establishing a limited pilot program requiring the Commission to approve undergrounding of a two-mile portion of the Pleasant View-Hamilton project (for which the Commission previously had rejected undergrounding), plus all or part of three more transmission lines of 230 kV or less by July 1, 2012. In 2011, the expiration date for this program was extended to July 1, 2014. The legislation establishes three criteria for a project to be eligible for approval as a qualifying pilot project: (1) undergrounding all or a part of a line must be technically feasible; (2) the estimated additional cost of undergrounding may not exceed 2.5 times the cost of placing the same line overhead (unless the public utility, affected localities and the Commission agree that a project not meeting this criterion may be accepted into the pilot program); and (3) the governing body of each locality in which a portion of the proposed line indicates, by general resolution, general community support for the line to be placed underground.

Q. What has been the Company's response to HB 1319?

A. The Garrisonville project was submitted prior to HB 1319 and was not eligible for inclusion in the HB 1319 program. The Commission approved undergrounding of the two-mile portion of the Pleasant View-Hamilton line, as required by HB 1319, in Case No. PUE-2008-00042. The Company filed applications, which were approved by the to qualify under HB 1319. As I have explained, the total Project cost of Alternative A for 2015 ($488.6 million) is the same as for Alternative B. Of this total cost, the cost attributable to a Surry-Skiffes Creek line is $439.8 million ($488.6 million total minus $46.4 million for the Skiffes Creek-Whealton line and $2.4 million for work at Whealton and other substations). The comparable costs for the proposed 500 kV line total $106.6 million ($155.4 million total minus the same $46.4 million and $2.4 million figures related to the Skiffes Creek-Whealton line). Comparison of the costs for these comparable facilities shows that the cost of facilities associated with the underground/overhead alternative 230 kV line to Skiffes Station is 3.13 times for HB 1319 comparison purposes for the proposed 500 kV overhead line for 2015. Adding the $26.7 million of additional facilities required for either 230 kV alternative to achieve full compliance for 2021 produces a total of $515.3 million for the 230 kV alternative. Of this total, the cost attributable to a Surry – Skiffes Creek line is $466.5 million ($515.3 minus $46.4 million for the Skiffes Creek-Whealton line and $2.4 million for work at Whealton and other substations). The comparable cost for the proposed 500 kV line for 2021 compliance is $123.9 million ($172.7 million total minus the same $46.4 million and $2.4 million figures related to the Skiffes Creek-Whealton line). This is 2.77 times the $ 123.9 million cost of the proposed 500 kV overhead line for HB 1319 purposes.

IV. 230 KV ALTERNATIVE ESTIMATES

Q. Please provide the Company's estimated cost of the additional transmission facilities that would be required for each of Alternatives A and B to resolve identified NERC Reliability Violations that are not resolved by those 230 kV alternatives.

A. These additional facilities are identified in Company Witness Nedwick's Rebuttal

Schedule 4, and the estimated costs of these facilities for Alternative A are shown on page 1 of my Rebuttal Schedule 4. The corresponding costs for Alternative B are shown on page 2 of that schedule.

Q. Please provide the Company's estimated cost for 230 kV Alternative C.

A. Currently, existing 230 kV Line #214 (Surry-Winchester) and Line #263 (Chuckatuck-Newport News), each with a transfer capability of approximately 500 MVA, cross the James River on common double circuit structures between Isle of Wight County and the City of Newport News. As described in the rebuttal testimony of Mr. Nedwick, Alternative C, suggested by JCC Witness Whittier, would tie the river crossing portions of these two circuits together to create one six-wire circuit between Chuckatuck and Newport News Stations, designated Line #263, with a combined transfer capability of approximately 1000 MVA. The river crossing portion of Surry-Winchester Line #214 would be replaced with a new single circuit river crossing with new 1000 MVA conductors.

Of course, the transfer capability of these rebuilt river crossings would be limited by the transfer capability of the onshore portions of these circuits unless they are rebuilt to provide approximately 1000 MVA. In the case of Line #214, this would mean rebuilding from the Isle of Wight side of the James River 30.29 miles back to Surry Power Station, and from the Newport News side 2.65 miles back to Winchester Station. In the case of Line #263, 6.25 miles would need to be rebuilt from the Isle of Wight side of the river back to Chuckatuck Station and 4.52 miles from the Newport News side back to Newport News Station. But this work only covers the facilities that are directly affected by this increase in transfer capability of these two circuits. Significant improvements also would be required to additional interconnecting facilities to prevent them from overloading due to the increased power flows on Line #214 and Line #263. As shown on page 3 of my Rebuttal Schedule 4, the total cost of improvements to rebuild Line #214 and Line #263 and address the resulting impacts on other facilities is $144.8 million.

Mr. Nedwick's rebuttal testimony also identifies a number of NERC Reliability Violations that are not resolved by Alternative C, lists the additional improvements to the transmission system that would be required to resolve those deficiencies and explains that the cost of these additional transmission system improvements must be included in the total cost of Alternative C. As shown on page 3 of my Rebuttal Schedule 4, we estimate the cost of these additional improvements to transmission facilities to be $82.1 for 2015 compliance and $181.9 million for 2021 compliance, bringing the total cost of Alternative C to $ 408.8 million. In addition, this work would require the postponement of the retirement of Yorktown Units 1 and 2 during the construction period of the 2015 compliance work, resulting in an additional $ 652 million for 2015 compliance. This would bring the total project costs to $1,060.8 million for 2015 compliance, which exceeds the $155.4 million of the Company's proposed Project by 6.83 times. Because the time to construct the transmission facilities for 2015 NERC Reliability Standards compliance (10 years) far exceeds the Project need date, no generation costs were prepared for 2021 compliance.

Q. Do you have any further comments regarding the constructability of Alternative C?

A. Yes. We have analyzed the feasibility of constructing Alternative C, which would require rebuilding most of the existing 230 kV system in the area. That analysis, which focused on the sequence for rebuilding the various components of the system and the feasibility of scheduling the outages of existing lines that would be required, shows that it would take a minimum of 10 years to complete just the construction required for 2015 NERC Reliability Standards compliance for Alternative C. Obviously, this is not a feasible solution to meet the identified electrical need date of June 1, 2015.

V. ISSUES RELATED TO THE BASF PROPERTY

Q. Do you agree with BASF Witness Vernon C. Burrows's comments on pages 9-12 of his testimony, regarding his assessment of the impact of the construction of the transmission line using the Updated Proposed Route?

A. No. Mr. Burrows has made several incorrect assumptions about our engineering and construction methods to support his position on page 2 of his testimony that the construction of the line using the "Variation 1 route would be a disaster." First, Dominion Virginia Power plans to use a pipe pile foundation design to support the transmission towers on BASF property, not Drilled Foundations as noted by Mr. Burrows on page 10 of his testimony. These pipe pile foundations will be approximately 42 inches in diameter and will be driven with a vibratory hammer to a depth of approximately 40-60 feet. This type of foundation design is minimally invasive and is generally considered to have little, if any, impact when used in sensitive areas such as wetlands as discussed by Company Witness Cathy Taylor. Additionally, Mr. Burrows's statement on page 10 of his testimony that it will be difficult to span the bluff at the river is not correct. The BASF Property already has a 115 kV line that transverses the property for over one mile to the Dow Substation located on the property, which supplies electricity to the property. The extension of this corridor to the River is another approximately 2,500 feet and in that expansion our preliminary design calls for four towers. As is also discussed by Company

230 kV Alternative A Costs for 2015 and 2021
(Millions in 2012 Dollars)

Single Circuit 230kV U.G. Hybrid

Surry - Skiffes Creek Line	$187.5
Skiffes Creek - Whealton Line	$46.4
Skiffes Creek Switching Station	$23.5
Surry Switching Station	$14.0
Whealton Substation	$2.0
Lanexa & Yorktown Substations	$0.4
Total	$273.8

Full Compliance Cost for 2015

Wreck & Rebuild 209 Line (Skiffes Creek - Yorktown)	$27.5
Temporary Line (285/209)	$0.7
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
Build 2nd 230kV Surry - Skiffes Creek Line	$166.6
Total	$214.8

Additional Full Compliance Cost for 2021

Add 230/115 Transformer at Whealton	$8.0
Wreck & Rebuild 34 Line (Skiffes Creek – Grafton – Harwood Mills)	$18.7
Total	$26.7

Total Cost	**$515.3**

230 kV Alternative B Costs for 2015 and 2021
(Millions in 2012 Dollars)

Double Circuit 230kV U.G. Hybrid

Surry - Skiffes Creek Line	$343.8
Skiffes Creek - Whealton Line	$46.4
Skiffes Creek Switching Station	$24.8
Surry Switching Station	$23.0
Whealton Substation	$2.0
Lanexa & Yorktown Substations	$0.4
Total	$440.4

Full Compliance Cost for 2015

Wreck & Rebuild 209 Line (Skiffes Creek - Yorktown)	$27.5
Temporary Line (285/209)	$0.7
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
Total	$48.2

Additional Full Compliance Cost for 2021

Add 230/115 Transformer at Whealton	$8.0
Wreck & Rebuild 34 Line (Skiffes Creek – Grafton – Harwood Mills)	$18.7
Total	$26.7

Total Cost	**$515.3**

Attachment 6

Company Exhibit No. 94
Witness: MSA
Rebuttal Schedule 4

230 kV Alternative C Costs for 2015 and 2021
(Millions in 2012 Dollars)

Line 214, 263, & 261 Rebuild

Wreck & Rebuild 263 Line (Chuckatuck – Newport News) (land)	$26.8
Wreck & Rebuild 214 Line (Surry – Winchester) (land)	$61.3
New Single Circuit River Crossing for 214 Line	$37.5
Wreck & Rebuild 261 Line	$11.2
Temporary Line (263 Wreck & Rebuild)	$6.4
Add Capacitor Bank at Peninsula Sub	$1.6
Total	$144.8

Full Compliance Cost for 2015

Wreck & Rebuild 2113 Line (Lanexa-Waller)	$36.3
Wreck & Rebuild 34 Line (Skiffes - Grafton)	$17.3
Wreck & Rebuild 234 Line (Winchester - Whealton)	$0.5
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
R/P Transformer at Lanexa	$8.0
Total	$82.1

Additional Full Compliance Cost for 2021

Wreck & Rebuild 209 Line (Waller - C&O)	$35.6
Wreck & Rebuild 209 & 285 (C&O - Yorktown)	$11.4
Wreck & Rebuild 2102 (Tower Section) - Chickahominy - Waller	$59.7
Reconductor 2102 (Steel Pole) - Chickahominy - Waller	$1.9
Wreck & Rebuild 99 Line (Peninsula - Whealton)	$17.3
Add Shellbank 230/115 Transformer	$8.0
Add Whealton 230/115 Transformer	$8.0
Add SVC at Skiffes Creek location	$40.0
Total	$181.9

Total Cost	**$408.8**

REBUTTAL TESTIMONY
OF
WALTER R. THOMASSON, III
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

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

A. My name is Walter R. "Trey" Thomasson, III, and I am an Engineer III, Electric Transmission Line Engineering for Dominion Technical Solutions, Inc. My business address is 701 East Cary Street, Richmond, Virginia 23219.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Electrical Engineering from Virginia Tech in 2003. I received a Master of Engineering Management degree from Old Dominion University in 2007. I am a Registered Professional Engineer in the Commonwealth of Virginia. I started my career with the Company as an Engineer II in Electric Transmission Operations Engineering in 2008. In 2011, I moved to Electric Transmission Line Engineering and was promoted to Engineer III in 2012. From 2004 to 2008, I was employed by the U. S. Department of Defense.

Q. What are your responsibilities as Engineer III, Electric Transmission Line Engineering?

A. My responsibilities are to design, engineer, and provide operational and maintenance support for underground high voltage transmission lines.

Q. Please describe the conceptual design of 230 kV Alternatives A and B.

A. The Company does not propose, and in fact opposes, undergrounding for any portion of the Surry-Skiffes Creek line. However, in response to the Hearing Examiner's direction, the following is a conceptual description of Alternatives A and B. For both alternatives involved, the line would need to start the river crossing south of the existing pipelines in Surry County so that they would not need to be crossed in the river. Also, the river crossing would not follow the overhead James River Crossing Variation 3 route across the river, but instead be a straight line across. For both alternatives, the straight line river crossing portion is approximately 4.0 miles, and the land portion in James City County is approximately 0.78 mile. The land portion in Surry County is approximately 1.5 miles for both an overhead and an underground route. Both alternatives were evaluated using a high-pressure fluid-filled ("HPFF") cable system for the underground portion and single shaft monopoles for the overhead portions.

II. CONCEPTUAL DESIGNS

Q. Please describe the conceptual design of 230 kV Alternative A.

A. The route of Alternative A, the single circuit hybrid line, is shown in my Rebuttal Schedule 1. Alternative A would leave the north side of the 230 kV switchyard at the Surry Station and run overhead on double circuit 500 kV monopoles (to accommodate a future 500kV line) and cross the intake canal for Surry Power Station before turning east to run along the northern bank of the canal for approximately a mile before turning south, crossing the canal and the three pipelines (two natural gas transmission and one petroleum products) and then leaving the Surry Power Station site into adjoining property where an overhead-to-underground transition station would have to be built on the Surry

County shore of the James River because there is no room for the transition station on the Company's property north of the pipelines, and the adjoining Hog Island Wildlife Management Area to the north is not available. From this transition station, the route would continue, as stated above, underground across the James River, as shown in my Rebuttal Schedule 1, to the James City County side. For the river crossing, the single circuit HPFF cable system would consist of three horizontal directional drills for an equal number of pipes, with two sets of intermediate splicing platforms in three locations (six total platforms). The pipes would need to be separated by 20 feet, with 120 feet between the first two pipes and the third pipe, as shown in my Rebuttal Schedule 2. This extra distance, which is needed for when the cables are spliced together and the pipe is "overboarded" into the river on each side of the splicing platform, requires a minimum right-of-way width of 240 feet. Once on land at the James River Crossing Variation 3 landing point, Alternative A would consist of one trench with three steel pipes, each containing three cables (a total of nine cables), as shown in my Rebuttal Schedule 3. Once the underground line reaches the transition station at BASF Drive, the line would continue overhead to Skiffes Creek on double circuit steel monopoles to incorporate the existing 115 kV line in existing right-of-way.

Q. Please describe the conceptual design of 230 kV Alternative B.

A. The route of Alternative B, the double circuit hybrid line, is shown in my Rebuttal Schedule 4. As stated in Section I.C.1 on page 56 of the Company's Appendix, a double circuit 230 kV overhead line cannot be built out of the Surry 230 kV Switching Station because that would preclude the Company from building a 500 kV line out of that location in the future. Accordingly, Alternative B would leave the south side of the

230 kV switchyard at Surry Station as underground lines and would parallel the existing transmission corridor in a south-easterly direction and would cross the existing natural gas and petroleum products pipelines before leaving the Surry Power Station property and continuing to a temporary workspace site on the adjoining property where the drill rig would be located to commence directional drilling for the underground river crossing. Just before getting to the James River, the pipes would spread before crossing the river. In the portion of Alternative B from the 230 kV switching station and where it enters the water, the cable system would consist of two parallel trenches, each with three steel pipes containing three cables (a total of 18 cables), as shown in my Rebuttal Schedule 5. The two trenches would be separated by 20 feet to reduce mutual heating effects in order to maximize the ampacity of the circuit, requiring a minimum right-of-way width of 50 feet. For the river crossing, the HPFF cable system would consist of six horizontal directional drills for an equal number of pipes, with three sets of intermediate splicing platforms in three locations (nine total platforms), as shown in my Rebuttal Schedule 6. The pipes would need to be separated by 20 feet, with 120 feet between each pipe pair, requiring a minimum right-of-way width of 400 feet. This extra distance is needed for when the cables are spliced together and the pipe is overboarded into the river on each side of the splicing platform. Once ashore on the James City County side, the underground cable system from the shore to the transition station on BASF Drive would be the same as shown in my Rebuttal Schedule 5. After leaving the transition station, the two 230 kV circuits would continue overhead to Skiffes Creek on double circuit monopoles, which would parallel and adjoin the existing 115 kV line all the way to the Skiffes Station site and would require expansion of the existing right-of-way to 150 feet.

Q. Will the adjoining property south of Surry Power Station be available to serve as the site for the transition station on the Surry side and/or the temporary construction workspace for the drilling rig?

A. In addition to a site of approximately 1 acre for a transition station, we also would need approximately 2.2 acres (single circuit – a 240 feet by 400 feet area) or 3.7 acres (double circuit – a 400 feet by 400 feet area) of additional land for temporary work space for the drilling rig. We don't know the availability of that adjoining land for these purposes. We also would need a permanent right-of-way through that land for the line itself.

Q. Please describe the equipment that would be needed to transition from the overhead line construction to underground cables.

A. For a single circuit underground transition station with 3 pipes, there would be a graveled, fenced area approximately 150 feet by 100 feet that would contain the following pieces of equipment:

- One overhead line backbone structure (75-foot steel H-frame)
- Multiple pipe stands for underground cable terminations, current transformers and surge arresters
- Control house for protective relays, communications equipment, batteries and battery charger
- A prefabricated enclosure approximately 12 feet high by 12 feet wide by 45 feet long also would be required for pressurization equipment for the HPFF cable system (located at one of the transition stations, with a corresponding hydraulic crossover cabinet at the other transition station)

Each of the underground cables must be terminated in a large porcelain bushing-type

**REBUTTAL TESTIMONY
OF
STEVEN R. HERLING
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029**

Q. Please state your name, position, place of employment and business address.

A. My name is Steven R. Herling. I am the Vice President of Planning for PJM Interconnection, L.L.C. ("PJM"). My business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497.

Q. What are your responsibilities at PJM?

A. As PJM's Vice President of Planning, I am responsible for the Resource Adequacy Planning Department, which develops the long-term load forecast for the PJM region and, in consultation with load-serving entities ("LSEs"), sets and enforces requirements for the sufficiency, adequacy, and availability of the generation resources needed to ensure reliable service to loads; the Interconnection Projects and Interconnection Analysis Departments, which process requests for and evaluate interconnections to the transmission system by new generation and merchant transmission projects; the Interregional Planning Department, which coordinates planning activities with neighboring transmission systems; and the Transmission Planning Department, which evaluates the reliability and market efficiency of the transmission grid and develops the Regional Transmission Expansion Plans ("RTEPs").

Q. Please provide your professional background while at PJM.

A. I have been employed by PJM since May 1990. While at PJM, I have contributed to or

Q. Turning to the specifics of this Project, JCC Witness Whittier questions PJM's analysis to the LS Power alternatives on pages 6-7 of his testimony. What LS Power alternatives were provided to PJM?

A. LS Power submitted several solution alternatives to PJM in response to the Chesapeake Energy Center ("CEC") and Yorktown Power Station ("Yorktown") generation deactivation notifications. On January 20, 2012, LS Power submitted a Great Bridge 500 kV proposal ("January 20 Great Bridge 500 kV proposal"), comprised of a number of different facility upgrades, intended to address the identified Reliability Violations that resulted from the CEC and Yorktown generation deactivation notifications.

On March 5, 2012, LS Power supplemented their original proposal with an additional recommendation to construct a new underground Surry-Skiffes Creek single circuit 230 kV cable and associated Phase Angle Regulator ("PAR") ("March 5 230 kV plus PAR proposal") in order to resolve those criteria violations. At that time, LS Power indicated that they were not ruling out the possibility that the line would ultimately be overhead, rather than underground. On April 19, 2012, LS Power again modified their proposal by withdrawing the January 20 Great Bridge 500 kV proposal to construct facilities not related to the James River crossing, focusing instead solely on the James River crossing from Surry-Skiffes Creek ("April 19 230 kV plus PAR underground proposal"). At that time, LS Power provided a cost estimate for a 230 kV under-river crossing and PAR. LS Power mentioned in the April 19 230 kV plus PAR underground proposal that they did not rule out an overhead crossing but were "initially skeptical of the technical feasibility" of an overhead crossing due to "sag issues" that could result in transmission towers "required to be over 1000 feet tall." On April 26, 2012, after PJM had posted their recommendation to submit the Project to the PJM Board for approval and the evening before PJM presented that recommendation to Stakeholders, LS Power proposed an overhead Surry-Skiffes Creek single circuit 230 kV facility plus PAR and provided a cost estimate for the circuit.

Q. How did the four different LS Power alternatives compare to the proposed Project to solve the Reliability Violations?

A. The proposed Project, in conjunction with several other proposed upgrades that are unrelated to the James River crossing all of which have since been classified as Pre-Projects by the Hearing Examiner's January 30, 2013 Ruling, solved all identified Reliability Violations resulting from the CEC and Yorktown deactivation notifications through the 15-year planning horizon. The long-term nature of the solution is particularly important in light of the lack of generation development in the area and the potential for further generation retirement.

The January 20 Great Bridge 500 kV proposal did not solve several criteria violations, including the overloads caused by the loss of the transmission facilities that cross the James River. Specifically, the loss of that tower line resulted in overloads of the Chickahominy-Waller 230 kV, Lanexa-Waller 230 kV and Yorktown-Whealton 230 kV lines. In addition, the January 20 Great Bridge 500 kV proposal did not resolve the NERC category C3 "N-1-1" criteria violation of the Huntsman-Thrasher 230 kV line. As a result, the January 20 Great Bridge 500 kV proposal was not considered to be a viable solution and, in any case, was withdrawn by LS Power on April 19, 2012 as discussed above.

PJM also evaluated the effectiveness of the 230 kV plus PAR underground proposal at the core of the March 5 and April 19 proposals. Operationally, the 230 kV Surry-Skiffes Creek line and PAR, whether underground or overhead, is a challenging solution. In order to make the 230 kV line effective, the PAR was added to the proposal to, essentially, force energy to flow across the line. However, the setting of the PAR, which determines the flow on the 230 kV line, impacts the energy flow on other transmission facilities on the Peninsula and south of the James River. There are a number of transmission line contingencies that would violate NERC Reliability Standards, absent the PAR. The PAR setting required to manage all of the contingency violations resulted in a very small operating margin between the operating limit of the PAR itself and Lanexa-Waller 230 kV line, which is conductor limited. Additional sensitivity analysis was performed to evaluate the retirement scenario of Yorktown Unit 2. For the Yorktown Unit 2 sensitivity, the 230 kV Surry-Skiffes Creek line and PAR is not a workable solution. There is no one setting that would allow the 230 kV line to operate without resulting in Reliability Violations on some other circuit. As a result, the 230 kV Surry-Skiffes Creek line and associated PAR was not considered to be a viable solution. By comparison, the proposed Project resolved all Reliability Violations, including those identified in the sensitivity analysis involving the retirement of Yorktown Unit 2.

Q. What actions did PJM and the PJM Board then take with respect to the Project?

A. Ultimately, PJM selected the 500 kV Surry-Skiffes Creek Project as the most effective solution and recommended it to the PJM Board for approval at their May 2012 meeting. The Board approved the Project based on operational considerations and its performance with respect to NERC Planning Standards, cost considerations, and the performance of the project in sensitivity analyses related to the possibility of further generation retirements at Yorktown. PJM then filed the cost allocation for the Project, along with others approved at that time by the PJM Board, with FERC in June 2012. FERC accepted the allocations in September 2012.

Q. What remedy did LS Power have to challenge PJM's selection of the Company's proposed Project over the LS Power proposals?

A. Their remedy would have been to invoke dispute resolution under the PJM Operating Agreement or, possibly, to file a timely protest of PJM's cost allocation filing at FERC.

Q. Did they take either action?

A. No.

Q. How were the Company's potential additional generation retirements factored into the RTEP analysis?

A. Based on public Dominion Virginia Power corporate documents, it was clear that additional generation at Yorktown was at risk of retirement. PJM performed sensitivity analyses to evaluate the performance of the various transmission projects should the Yorktown Unit 2 generation retire in addition to Yorktown Unit 1. Based on this analysis, the Company's proposed 500 kV Surry-Skiffes Creek line remained the most effective solution. The 230 kV Surry-Skiffes Creek line and associated PAR proved to be ineffective, with additional NERC Reliability Violations arising, including overloads to the PAR, itself. These violations would result in even greater costs associated with that project as additional infrastructure is required to ensure compliance with NERC Reliability Standards. As of this writing, PJM has received notice of the intended retirement of Yorktown Unit 2.

Attachment 9

APPLICATION OF VIRGINIA ELEC. & POWER COMPANY D/B/A DOMINION VIRGINIA POWER

FOR APPROVAL AND CERTIFICATION OF ELECTRIC FACILITIES: SURRY-SKIFFES CREEK 500 KV TRANSMISSION LINE, SKIFFES CREEK-WHEALTON 230 KV TRANSMISSION LINE, AND SKIFFES CREEK 500 KV-230-KV-115 KV SWITCHING STATION

CASE NO. PUE-2012-00029

REPORT OF ALEXANDER P. SKIRPAN, JR.
SENIOR HEARING EXAMINER

AUGUST 2, 2013

One factor that may suggest the use of the proposed Chickahominy-Skiffes Creek route is that this route uses Company-owned right-of-way and would require little additional right-of-way acquisition.[1255] However, 24.9 miles of the Company-owned right-of-way is an unused right-of-way purchased in the early 1970s.[1256] As demonstrated by the testimony of many of the public witnesses in this case, for people living near the unused right-of-way, from a public impact perspective, there is little difference between constructing a new transmission line on a new right-of-way and an unused existing right-of-way.

In summary, I find that the Proposed Alternative Project provides electrical reliability comparable to the Proposed Project, but its longer route would have a significantly greater adverse impact on the scenic assets, historic districts, and environment than that of the Proposed Project.

230 kV Transmission Options

In its Application, Dominion Virginia Power reported that it had compared the Proposed Project and the Proposed Alternative Project to several 230 kV transmission options including: (i) an overhead Surry-Skiffes Creek Double Circuit 230 kV transmission line following the original proposed route; (ii) an overhead Chickahominy-Skiffes Creek Double Circuit 230 kV transmission line following the Proposed Alternative Route; and (iii) an underground Surry-Skiffes Creek 230 kV transmission line.[1257] The Company contended that each of these alternatives failed to resolve all of the NERC reliability violations through 2021, with only the overhead Chickahominy-Skiffes Creek Double Circuit 230 kV transmission line resolving the NERC reliability deficiencies in 2015 and 2016.[1258]

Staff witness Chiles conducted an independent analysis of the Company's load-flow studies for each of the 230 kV transmission options examined by Dominion Virginia Power, and concluded:

> none of the 230 kV line alternatives are viable alternatives to the [Proposed Project] in terms of meeting the identified reliability need. Additionally, from an engineering perspective, none of the 230 kV options can be feasibly constructed to achieve the approximate 5,000 MVA capacity afforded by the [Proposed Project]. This additional capacity will be available to address long-term load growth in the Hampton Roads area.[1259]

Nonetheless, in his prefiled direct testimony, Mr. Chiles expressed concern regarding whether the 230 kV transmission alternatives had been sufficiently analyzed by the

[1255] Exhibit No. 83, Attached Exhibit WDM-1, at 22.
[1256] *Id.*
[1257] Exhibit No. 23, Attached Appendix at 55-58, 61.
[1258] *Id.*
[1259] Exhibit No. 79, at 24.

Company.[1260] In his prefiled direct testimony, Mr. Chiles recommended that several additional load flow studies be undertaken in this proceeding.[1261] In his prefiled direct testimony, James City County witness Whittier was also critical of the Company's consideration of 230 kV transmission alternatives.[1262] Among other things, Mr. Whittier proposed to reconductor or rebuild the Surry-Winchester Line #214 and Chuckatuck-Newport News Line #263, which serve the Peninsula from the south as an additional 230 kV transmission alternative.[1263]

Accordingly, in the *January 30 Ruling*, Dominion Virginia Power was directed to run additional load flow studies to incorporate the 2013 PJM Load Forecast, and to test various transmission and generation scenarios for the years 2015 and 2021. Among other things, these additional load flow studies included three 230 kV transmission alternatives: (i) Alternative A – Single-circuit 230 kV hybrid line (crossing under the James River); (ii) Alternative B – Double-circuit 230 kV hybrid line (crossing under the James River); and (iii) Alternative C – Rebuild and reconfiguration of existing 230 kV Lines #214 and #263 crossing above the James River between Isle of Wight County and Newport News.[1264] Company witness Nedwick reported that none of the 230 kV transmission options resolved all of the NERC reliability violations in 2015 or in 2021.[1265]

Mr. Nedwick summarized the NERC reliability violations for 2015 for the three 230 kV Alternatives as follows:[1266]

	NERC Category Tests			
Study	Category A	Category B	Category C	Category D
Study 6A – No Critical System Condition	0	0	9	3
Study 6B – No Critical System Condition	0	1	4	0
Study 6C – No Critical System Condition	0	5	122	8
Study 7A – Surry Unit 1 as the Critical System Condition	0	3	N/A	N/A
Study 7B – Surry Unit 1 as the Critical System Condition	0	2	N/A	N/A
Study 7C – Surry Unit 1 as the Critical System Condition	0	70	N/A	N/A

Mr. Nedwick also reported three 230 kV Alternatives would fail to resolve the following number of NERC reliability violations for 2021:[1267]

1260 *Id.* at 19-20; Staff Brief at 12.
1261 Exhibit No. 79, at 33-34.
1262 Exhibit No. 68, at 9.
1263 *Id.* at 11-12.
1264 Exhibit No. 87 at 8-9, Attached Rebuttal Schedule 2.
1265 *Id.* at 9, 12; Exhibit No. 90, at 7-9.
1266 Exhibit No. 90, Attached Rebuttal Schedule 4, at 16-18.
1267 *Id.*

Study	NERC Category Tests Category A	Category B	Category C	Category D
Study 13A – No Critical System Condition	0	9	113	7
Study 13B – No Critical System Condition	0	1	12	0
Study 13C – No Critical System Condition	0	12	182	13
Study 14A – Surry Unit 1 as the Critical System Condition	0	1	N/A	N/A
Study 14B – Surry Unit 1 as the Critical System Condition	0	0	N/A	N/A
Study 14C – Surry Unit 1 as the Critical System Condition	0	39	N/A	N/A

During the April Hearing, Mr. Chiles testified that he reviewed and ran the power flow models underlying the Company's additional analysis and was able to verify the Company's results.[1268] Indeed, Mr. Chiles also verified that the Proposed Alternative Project would perform similarly to the Proposed Project, using the updated information incorporated into the studies performed as directed by the *January 30 Ruling.*[1269] Mr. Chiles reported that in 2015, under Alternative A, overloads in violation of NERC reliability criteria would occur on the 230 kV Surry-Skiffes Creek Line, itself; the Lanexa-Waller Line #2113; Skiffes-Yorktown Line #209; and the Suffolk 500-230 transformer.[1270] Mr. Chiles confirmed that in 2015, under Alternative B, overloads in violation of NERC reliability criteria would occur on the Skiffes-Yorktown Line #209, and the Suffolk 500-230 transformer.[1271] Finally, Mr. Chiles testified that in 2015, for Alternative C, overloads in violation of NERC reliability criteria would occur on Lanexa-Walker Line #2113, Lanexa-Yorktown Line #34, Whealton-Winchester Line #234, Suffolk 500-230 transformer, and Lanexa 230-115 transformer.[1272] Mr. Chiles confirmed that all of the above violations of NERC reliability criteria are resolved by the Proposed Project.[1273]

Based on the uncontested load flow results, I find that none of the 230 kV transmission alternatives, by themselves, satisfy the NERC reliability requirements for 2015, or for 2021.

However, as directed in the *January 30 Ruling*, Dominion Virginia Power estimated the additional overhead transmission facilities, and their cost, necessary to resolve all of the NERC reliability violations for both 2015 and 2021.[1274] Company witness Allen presented the additional transmission projects necessary to resolve all of the NERC reliability violations and showed that only a double-circuit 230 kV hybrid transmission line would resolve all of the

[1268] Chiles, Tr. at 1068.
[1269] *Id.* at 1071.
[1270] *Id.* at 1073; Staff Brief at 13; Exhibit No. 90, at 7.
[1271] *Id.*; *Id.*; *Id.* at 8.
[1272] *Id.*; *Id.*; *Id.* at 9.
[1273] Chiles, Tr. at 1074.
[1274] *See supra* at p. 114.

NERC reliability violations for 2015.[1275] Because the Company was unable to determine a transmission solution that would resolve all of the NERC reliability violations for 2015, I find that Alternative A – Single-circuit 230 kV hybrid line should be eliminated from further consideration. Dominion Virginia Power argued against Alternative B and Alternative C, after the inclusion of additional transmission projects that resolve all of the NERC reliability violations based on the significantly higher cost associated with these alternatives and because construction of these alternatives cannot be completed by the June 2015 need date.[1276] Cost and the need date will be discussed in detail below.[1277]

Generation Options

As directed in the *January 30 Ruling*, Dominion Virginia Power determined that it would take two new generating units in the North Hampton Roads Load Area with a combined 620 MW capacity, with the size of the smallest unit of 295 MW, to resolve all of the NERC reliability violations for 2015.[1278] To resolve all of the NERC reliability violations for 2021, Dominion Virginia Power reported that it would take an additional 618 MW of generation.[1279] Dominion Virginia Power argued against a stand-alone option based on the significantly higher cost associated with the stand-alone generation and because construction of the stand-alone generation cannot be completed by June 2015 need date.[1280] Cost and the need date will be discussed in detail below.[1281]

In addition, Staff witness Chiles modeled injecting new or increased generation at the proposed Skiffes Creek Switching Station, the proposed Brunswick power station, and reviewed the Company's stand-alone generation studies.[1282] Mr. Chiles found that the injection of an additional 550 MW of generation at Skiffes Creek would not resolve all of the NERC reliability criteria violations for 2015 and 2016.[1283] Similarly, Mr. Chiles reported that generation in "Brunswick County – even if approved by the Commission and constructed in a timely fashion – would not address [Dominion Virginia Power's] transmission needs identified in the instant case."[1284] Finally, Mr. Chiles confirmed the Company's studies concerning stand-alone generation.[1285]

On brief, James City County faulted the Company for failing to consider other generating options such as repowering the Yorktown units with liquefied natural gas ("LNG") or off-shore wind.[1286] However, Company witness Kelly testified that LNG was considered for repowering

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[1275] *Id.*; Exhibit No. 93, Attached Rebuttal Schedule 4, at 1.
[1276] Company Brief at 32-34; Exhibit No. 130, Attached Rebuttal Schedule 1.
[1277] *See infra* pp. 152-55.
[1278] Exhibit No. 87, Attached Rebuttal Schedule 3; Exhibit No. 90, at 23.
[1279] *Id.*; *Id.*
[1280] Company Brief at 33-34; Exhibit No. 130, Attached Rebuttal Schedule 1.
[1281] *See infra* pp. 152-55.
[1282] Staff Brief at 16.
[1283] *Id.* at 17; Exhibit No. 79, at Attached JWC-2, at 13-15.
[1284] *Id.* at 18; Exhibit No. 81.
[1285] Chiles, Tr. at 1068-69.
[1286] James City County Brief at 26, 47-48.

Yorktown, but was rejected based on cost and the difficulty of getting a permit to build an import facility in a populated area like Yorktown.[1287] As for off-shore wind, because of the required transmission infrastructure for such generation, I find advocating off-shore wind generation is inconsistent for a party opposing the construction of a 500 kV transmission line. The 2012 NCTPC-PJM Joint Interregional Reliability Study entered into the record by James City County, stated that "[i]ntegration of 3,000 to 10,000 MW of off-shore wind in North Carolina and Virginia would require approximately $1-2 billion in transmission upgrades."[1288] The report stated that integration of such power into PJM would require a new 500 kV substation and upgrades to the 500 kV system and local 230 kV network.[1289] Indeed, the report listed six new transmission lines required in Virginia, including a forty-five mile, 500 kV Surry to Chickahominy transmission line.[1290]

Combinations of 230 kV Transmission and Generation

As directed in the *January 30 Ruling*, Dominion Virginia Power studied the amount of additional generation that would be required to be added to each of the 230 kV transmission alternatives to eliminate all projected NERC reliability violations for 2015 and 2021. Company witness Nedwick testified that to eliminate all projected NERC reliability violations for 2015: (i) if Alternative A – single-circuit 230 kV hybrid line is constructed, an additional 1,008 MW of generating capacity would be required; (ii) if Alternative B – double-circuit 230 kV hybrid line is constructed, an additional 159 MW of generating capacity would be required; and (iii) if Alternative C – the rebuild and reconfiguration of existing 230 kV Lines #214 and #263 is undertaken, an additional 522 MW of generating capacity would be required, with 56 MW being the minimum size of a generating unit that must remain in service.[1291] Mr. Nedwick stated that to eliminate all projected NERC reliability violations for 2021: (i) if Alternative A and the additional generating capacity is constructed for 2015, an additional 1,449 MW of generating capacity would be required, with 87 MW being the minimum size of a generating unit that must remain in service; (ii) if Alternative B and the additional generating capacity is constructed for 2015, an additional 551 MW of generating capacity would be required, with 27 MW being the minimum size of a generating unit that must remain in service; and (iii) if Alternative C and the additional generating capacity is constructed for 2015, an additional 505 MW of generating capacity would be required, with 139 MW being the minimum size of a generating unit that must remain in service.[1292]

Similar to stand-alone generation, Dominion Virginia Power and Staff opposed combinations of 230 kV transmission and generation primarily based on cost and the time to complete.[1293] These topics will be addressed below.[1294]

[1287] Kelly, Tr. at 1622-23, 1626-27.
[1288] Exhibit No. 133, at 3.
[1289] *Id.* at 2.
[1290] *Id.* at 26.
[1291] Exhibit No. 87, Attached Rebuttal Schedule 3, at 3.
[1292] *Id.*
[1293] Company Brief at 33-34; Staff Brief at 38-41.
[1294] *See infra* pp. 152-155.

Whittier's Variations

During the hearing, James City County witness Whittier offered two additional alternatives: (i) Whittier's Variation of Alternative A – 230 kV transmission hybrid (under river crossing) from Surry to Whealton without Skiffes Creek Switching Station;[1295] and (ii) Whittier's Variation of Alternative C – New 230 kV overhead transmission line from Chuckatuck to Whealton (collectively, "Whittier's Variations").[1296] On brief, James City County argued that Whittier's Variations "reasonably [address] all issues consistent with NERC requirements," would be "reasonable in cost," and could be "constructed in a timely manner."[1297]

Company witness Nedwick contended that based on a "high-level quick assessment," Whittier's Variation of Alternative A failed to resolve all NERC reliability violations, with overloads to the Lanexa 230 to 115 auto transformers, Suffolk 500 to 230 transformers, both Whealton 230 to 115 transformers, and Line #99.[1298] Similarly, Mr. Nedwick found that Whittier's Variation of Alternative C failed to resolve all of the NERC reliability violations.[1299] Mr. Nedwick maintained that because Whittier's Variations connected directly to Whealton, electrically, they were both variations to Alternative C of the *January 30 Ruling*.[1300]

Mr. Whittier acknowledged that his proposed variations failed to resolve all NERC reliability violations. For example, for Whittier's Variation to Alternative A, he reported "a couple . . . problems with Category B violation," such as a 106 percent loading of a transformer.[1301] As for Whittier's Variation to Alternative C, he testified that "an initial look still showed us . . . more violations . . . than we wanted to see."[1302] To address some of these violations, Mr. Whittier recommended the addition of another 500 to 230 kV transformer at Surry, but still admitted that such an addition only "solves almost everything. Not everything."[1303]

On brief, James City County tried to bolster Whittier's Variations with the testimony of Staff witness Chiles. James City County maintained that "[w]hen given the opportunity, he did not contest that Whittier alternatives would resolve the NERC issues and in fact expressed the firm opinion that Whittier and he could find alternatives that addressed all of the NERC issues."[1304] I disagree. Mr. Whittier presented his variations for the first time during oral testimony on the morning of April 15, 2013. Mr. Chiles appeared as a witness on the afternoon of the same day. Mr. Chiles had not reviewed Mr. Whittier's analysis and expressed no opinion:

1295 Whittier, Tr. at 909-13; Exhibit No. 69.
1296 *Id.* at 940-941; Exhibit No. 71.
1297 James City County Brief at 24.
1298 Nedwick, Tr. at 1298.
1299 *Id.* at 1303.
1300 *Id.* at 1299-04.
1301 Whittier, Tr. at 936.
1302 *Id.* at 940.
1303 *Id.* at 941.
1304 James City County Brief at 35, citing Chiles, Tr. at 1089, 1110.

Q. The NERC violations, you just simply haven't looked at [Mr. Whittier's] analysis, so you really can't say whether they do or do not really solve the NERC problems at this point?

A. That's correct.[1305]

Nonetheless, Mr. Chiles raised two criticisms of Mr. Whittier's approach that undermined the usefulness of Whittier's Variations in this case. The first criticism ties into Mr. Nedwick's observation that by running both variations directly to Whealton, electrically, Mr. Whittier has offered two variations of Alternative C. That is, by eliminating the Skiffes Creek Switching Station, neither of Whittier's Variations can resolve NERC violations by feeding power to the North. Mr. Whittier looked at the cause of projected NERC violations on the 230 kV transmission lines crossing under the James River and stated:

> And as I looked at it, a lot of that – some of that overload wasn't because of the need down in the south near the Whealton area, but it was because they had interjected a new substation at Skiffes Creek that was drawing some power from those new circuits, too. So instead of the north relying on the lines from the north around Chickahominy, they're also relying – they're taking power from this new crossing, so that together with the power that was going down to Whealton overloaded the new lines.[1306]

Mr. Chiles took issue with Mr. Whittier's approach for failing to consider the interrelated power flow problems that can be caused by losing power to the Peninsula from either the North or the South.[1307] Mr. Chiles stated his concern as follows:

> So my concern with [Whittier's Variations] on the south side once again is you haven't really solved the issue of a strong source in the middle of the peninsula. . . .
>
> It's really twofold. The strong source, number one, serves basically as a surrogate, if you will, for the Yorktown generation. So it's reasonable to assume that that makes sense.
>
> The other thing is by splitting up the 230 lines coming from Chickahominy going down further, going down to Whealton, by splitting those circuits and injecting power at . . . [Skiffes Creek], what we're really doing is we're sending power throughout the peninsula both north and south in that case, which is going to create a counterflow to resolve the generator deficiencies in the north, which is going to solve NERC violations to the north. It's also going to deal with the issues of the generation load deficiency

1305 Chiles, Tr. at 1110.
1306 Whittier, Tr. at 910.
1307 Chiles, Tr. at 1109; *See supra* at p. 133.

> in the south at that injection point, as well. . . . [W]hat we're really doing is lessening the generation load balance, so we're reducing flows across the northern and southern circuit sends into the system.[1308]

James City County contended that the remaining NERC violations may also be addressed by other simple measures such as DSM.[1309] However, for transmission planning purposes, PJM builds DSM forecasts into its load forecasts for each of the coming three years based on the amounts that have been committed in the RPM auction for the particular delivery years.[1310] Consequently, for 2015, the amount of DSM reflected in the 2012 load forecast is based on the results of the RPM auction for that year.[1311] In addition, Company witness Herling outlined the practical problems of relying on DSM to solve NERC reliability violations, such as the DSM requirement of a two-hour notification, which would be ineffective in response to an instantaneous event.[1312] Accordingly, I find that DSM is already considered in PJM's transmission planning process and additional amounts should not be assumed to be available to address projected NERC reliability violations.

Based on the record in this case, I find that Whittier's Variations fail to resolve all of the NERC reliability violations and do not appear to address all of the NERC violations the Project is designed to solve.

Mr. Chiles' second criticism of Whittier's Variations concerns a fundamental difference in transmission planning between the two witnesses. Both Mr. Whittier and Mr. Chiles testified to the difficulty of accurately forecasting the future and the resulting need for flexibility to be designed into a transmission system.[1313] However, the witnesses advocated opposite approaches for creating flexibility in the Company's transmission system. Mr. Whittier advocated an approach that could be expanded as needed and would address future NERC violations on an individual basis.[1314] For example, Mr. Whittier advised that "[m]y longer term plan, if I go beyond 2021, or if load grows a lot more than expected, is that I might put in both of these 230 kV alternatives that we've talked about . . . ."[1315] On the other hand, Mr. Chiles advocated the Proposed Project, with its 5000 MVA to address the NERC violations identified in 2015 and 2021, and provide for expected future load growth.[1316] Mr. Chiles contended:

> So rather than piecemealing a solution where you have, say, a line that's loaded at 1000 MVA and you put something in that when it goes into power flow is loaded at 995, and then a year later you're building something else, the capacity of . . . [Surry-

[1308] *Id.* at 1109-11.
[1309] James City County Brief at 25-26.
[1310] Exhibit No. 92, at 11-12.
[1311] *Id.*
[1312] Herling, Tr. at 1380.
[1313] Chiles, Tr. at 1099-1100; Whittier, Tr. at 943-45.
[1314] Whittier, Tr. at 908, 945.
[1315] *Id.* at 965.
[1316] Chiles, Tr. at 1099.

Skiffes Creek Line] gives some flexibility for operations in the future and a lot of growth in the future.[1317]

Mr. Whittier's approach may be appropriate in an area with relatively stable load, and where the siting of future or additional transmission facilities would be easy and without impact on scenic assets, historic districts, and the environment. Such a situation is not present in this case. I agree with Mr. Chiles, and Dominion Virginia Power, that from an operational or electrical perspective, the Proposed Project provides the flexibility to address both the NERC violations and expected or possible future load growth.

Other fallacies of a piecemeal approach include cost and efficiencies. More importantly, the added impacts of the likely additional future projects on scenic assets, historic districts, and the environment argue against such an approach. Under Mr. Whittier's plan, both of Whittier's Variations may need to be constructed. Even more transmission may need to be constructed in the Chickahominy area to relieve NERC violations to the north that Whittier's Variations do not address. Thus, instead of the impacts of one transmission line and switching station, within a few years, the area could be impacted by the construction of a transmission line from Surry to Whealton, and a second overhead transmission line constructed from Chuckatuck to Whealton. Company witness Harper presented a preliminary routing map for Mr. Whittier's proposed Chuckatuck to Whealton transmission line and outlined several routing constraints including: (i) expansion of the existing right-of-way through residential and business developments; (ii) crossing a wide expanse of wetlands; (iii) a new crossing of the James River; (iv) routing across land owned by the City of Newport News and thus, not subject to eminent domain; and (v) the siting of two underground terminals; and (vi) beginning the process for approval of a new transmission line, including open houses, state agency review, and a new application with the Commission.[1318]

Moreover, to address NERC violations in the Chickahominy area and to the north, additional transmission lines may need to be built in the Chickahominy area. Consequently, under a piecemeal approach, it is possible that after building one or both of Mr. Whittier's Variations, PJM could again direct Dominion Virginia Power to undertake a project similar to the Proposed Project or the Proposed Alternative Project.

Accordingly, I find that Whittier's Variations should not be considered as viable alternatives in this proceeding based on their failure to resolve all of the NERC reliability violations, and because addressing NERC reliability violations by such a piecemeal approach in such a growing and constrained area creates the risk that system reliability ultimately will require multiple additional projects with multiple additional impacts on scenic assets, historic districts, and the environment.

[1317] *Id.*

[1318] Harper, Tr. at 1683-84; Exhibit No. 119.