Dominion Virginia Power
701 East Cary Street, Richmond, VA 23219

Mailing Address: P.O. Box 26666
Richmond, VA 23261

dom.com

Dominion

December 15, 2015

United States Army Corps of Engineers
Norfolk District
Attention: Randy Steffey
803 Front Street
Norfolk, VA 23510-1011

Re: NAO-2012-0080113-V0408, Surry-Skiffes-Whealton, Dominion Virginia Power Response to National Parks Conservation Association/Princeton Energy Resources International Comments "Dominion's Proposed 'Surry-Skiffes Creek Project' – Issues and Alternatives," dated November 13, 2015

Dear Mr. Steffey:

On behalf of Dominion Virginia Power ("DVP" or "Dominion"), I am writing to respond to a document entitled "Dominion's Proposed 'Surry-Skiffes Creek Project' – Issues and Alternatives," prepared by National Parks Conservation Association ("NPCA") and Princeton Energy Resources International ("PERI") and dated November 13, 2015 ("NPCA/PERI Comments" or the "Comments") that has been submitted to the Corps as a public comment in this proceeding.

DVP has previously provided the Corps with a detailed explanation of why and how the need for the proposed Surry-Skiffes-Whealton Project (the "Proposed Project") must be, and has been, properly determined in accordance with mandatory federal transmission planning and modeling reliability standards established by the North American Electric Reliability Corporation ("NERC") and approved by the Federal Energy Regulatory Commission ("FERC"). See Attachment 1 to Courtney Fisher's August 14, 2014 letter to Tom Walker of the Corps ("April 14 Letter"). A copy of that Attachment 1 is attached to this letter. The Federal Power Act ("FPA") requires, as a matter of federal law, adherence to these "NERC Reliability Standards," which impose requirements for compliance with certain specific criteria, data and methodologies, including computer modeling, to ensure the reliability of the transmission grid in North America. FERC is the agency of the federal government vested by the FPA with exclusive jurisdiction to determine and regulate the reliability of the electric transmission grid.

In summary, the NCPA/PERI Comments do not present any practicable alternatives to the Proposed Project. The Comments' suggestions to determine electrical reliability based (a) on the Comments' so-called "Revised Peak Load Forecast" (pages 10-26), which is based on inaccurate date and assumptions, or (b) on a methodology purporting to "manage peak loads" without Yorktown Units 1 and 2 (pages 26-28), would violate the NERC Reliability Standards and the FPA. The Comments' request (pages 28-30) for yet another "re-evaluation" of submarine cable alternatives demonstrates the authors' unawareness of the extensive evidence on this subject previously considered by regional and state authorities and the Corps. Finally, the Comments' unsupported claims that economic impacts have not been considered are false.

As noted in Attachment 1, violations of the criteria provided in these NERC Reliability Standards, which drive 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 specified data inputs for all transmission system elements. The mandatory computer modeling is used to predict how system elements such as switches, transformers, and transmission lines will behave under different operating circumstances, including high winds, and other weather events, unanticipated equipment failure, cyber attack and swinging load levels. The NERC-required computer models, called power flow studies or load flow studies, also account for future growth in the system and the load it serves.

PJM and DVP use these models to determine what new facilities need to be included in PJM's annual Regional Transmission Expansion Plan ("RTEP"). The RTEP process is implemented by PJM (and its transmission owner members including DVP) using NERC-compliant processes, criteria and methodologies approved by FERC and audited by NERC. These include power flow studies that show the operating results of 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 ("DSM") response and gains in energy efficiency), interconnections of new generation units and additions of new or replacement transmission facilities.

The FERC-approved PJM RTEP process, using the power flow studies required by the NERC Reliability Standards, determined that (1) the planned retirement of Yorktown Units 1 and 2 would result in extensive thermal and voltage violations of NERC Reliability Standards on DVP's transmission system in the North Hampton Roads Load Area ("NHRLA") beginning June 1, 2015 and (2) the Proposed Project, which will provide a new 500 kV source into the NHRLA, would resolve all of those violations and is the best solution. Indeed, the Comments recognize on page 6 --as they must -- that "Load Flow modeling is used to forecast reliability violations so problems can be addressed before they occur" and that such studies "conclude that if the proposed project is not in service before retirement of Yorktown Power Station Units 1 and 2, NHRLA will not meet the Reliability Standards of [NERC] and load shedding will result."

Because NPCA does not like these results, however, it now seeks to change the federally mandated methodologies and inputs that produced them. The primary focus of the Comments (pages 10-26) is the following claim by the authors (page 31):

> The electrical load flow studies performed by Dominion and confirmed by PJM staff were performed using standard models and methods. However, several of the key operational and demographic assumptions going into the

economic models regarding future loads and generation appear significantly out of date or inaccurate, and the model algorithms that were used to project peak loads are now considered flawed. In brief, the Dominion study significantly overestimates NHRLA growth, including peak loads, and it underestimates: a) the availability of DSM capacity to reduce peak loads, b) the growth of distributed generation, and c) the increasing effectiveness of efficiency measures and energy reduction programs. These flaws result in exaggerated forecasts of rolling brown- or blackouts up to 80 events a year.

The Comments assert further that the aspects of the RTEP methodology that the authors consider to be "flawed" can simply be discarded in order "to reduce, reconfigure or eliminate the need for the project" (page 6). Specifically, the Comments assert that the RTEP's methodology for projecting future load growth should be rejected and replaced by a purported "Revised Peak Load Forecast" developed by the authors -- using protocols and inputs other than those required by the NERC Reliability Standards -- to support NPCA's opposition to the Proposed Project.

But regardless of projections of local growth, only NERC, subject to FERC review and approval, can make such a determination and/or change the requirements of the NERC Reliability Standards for such standard models and methods, or the algorithms to be utilized. And only FERC can approve changes to the PJM Open Access Transmission Tariff provisions that govern PJM determinations of which new transmission facilities need to be constructed. To do as the Comments suggest would violate the FPA and the NERC Reliability Standards, which DVP cannot and will not do.

Not only would reliance on the Comments' "Revised Load Forecast" violate the NERC Reliability Standards, it is refuted both by its use of inaccurate data and assumptions and by the actual current operating circumstances in the NHRLA. For example, the Comments (page 11) claim that Figure 4 (page 12) shows a 4000 MW "forecast error" between the peak load forecasts and actual load for PJM's Dominion Zone ("DOM Zone") in 2012 -2014, which the Comments equate to a 400 MW error in the NHRLA. But the load forecast values shown in Figure 4 are for DOM Zone, which includes the load for all retail customers in DOM Zone, while the actual load values are for only the retail customers served by DVP, which constitute approximately 82% of the total load in DOM Zone. No forecast error is shown by this inherently false comparison. The Comments also ignore the fact that, as required by Virginia law, the Virginia SCC and its independent expert consultants verified the power flow studies and modeling algorithms used to develop them.

In any event, the difference between forecasted and actual loads in the NHRLA is essentially an academic exercise because, as stated in Section 3.1.3 of the Stantec Alternatives Analysis (filed January 8, 2015), existing system load in the NHRLA already exceeds the capability of the transmission system without Yorktown Units 1and 2.

The Comments' misunderstanding of the NERC Reliability Standards is further demonstrated by their assertion (page 7) that violations of NERC Reliability Standards are merely a "useful metric to show how often the load in a particular balancing area exceeds a threshold that is set at a safe margin ('reserve margin') below the available power (transmission and generation capacities)." This is incorrect and a fundamental misstatement of the NERC Reliability Standards, which are not a 'useful metric' but a requirement of federal law and have nothing to do with reserve margin. The NERC Reliability Standards establish mandatory requirements under federal law for planning the transmission system to determine, through specified types of power flow studies, whether specific reliability criteria will be met as to each element of the transmission system under specific types of operating conditions. In contrast, the calculation of a "reserve margin" is used in generation planning to ensure that there is a sufficient amount of available generation capacity to serve overall system load -- a determination separate and independent from DVP's obligation to comply with the NERC Reliability Standards for transmission planning.

DVP also cannot comply with the NERC Reliability Standards by "managing" load shedding after the retirements at Yorktown based on assumptions that unproven levels of demand-side management ("DSM") and solar PV will be available or economic and that Yorktown Unit 3 could be operated more despite its environmental operating limitations and out-of-market cost, as the Comments claim (page 26-28). Regardless of the efficacy of these claimed alternatives, however, DVP must comply with the NERC Reliability Standards by observing the specific criteria and methodologies for determining compliance, as described above and in Attachment 1.
In fact, these alternatives are not practicable.

As noted on page 5 of the Corps' October 1, 2015 Preliminary Alternatives Conclusions White Paper ("White Paper"), the results of demand-side management resources are already accounted for in the transmission planning process that produced the Proposed Project. While solar PV has important attributes, the fact that it is both intermittent and non-dispatchable means that it cannot reliably be turned on to meet critical needs during periods of peak demand, such as the 7:00 am daily peak during the winter. This is why for planning purposes PJM treats a MW of solar capacity as equal to 38% of a fossil-fueled MW. It was determined in the SCC proceeding that, if the Proposed Project were not built, 620 MW of new gas-fired generation would be required at Yorktown Power Station for the transmission system to comply with NERC standards. Using PJM's conversion factor, this would equate to construction of approximately 1,630 MW of solar PV at Yorktown. Applying DVP's experience that 8-10 acres of land is required for each MW of new solar PV, this would require the acquisition of at least 13,040 acres in proximity to Yorktown Power Station. This is an area only a bit smaller than the City of Petersburg (14,675 acres), or almost 10,000 football fields. Even if it were possible to develop this amount of solar PV in the right location, construction of backup dispatchable generation (such as combustion turbines) in the vicinity of Yorktown would also be required because of the intermittent and non-dispatchable nature of solar.

Virginia law requires DVP approval from the State Corporation Commission of Virginia ("SCC") for construction of the Proposed Project. The Virginia Supreme Court has affirmed the SCC's determination of need for new transmission facilities based on violations of NERC Reliability Standards. After more than 18 months of exhaustive investigation and hearings, the SCC found that the Proposed Project is needed to resolve the identified NERC Reliability Violations and that the route reasonably minimizes adverse impact on the scenic assets. As shown in Attachments 2 and 3, the evidence in the SCC proceeding demonstrated that none of the alternatives suggested by the Comments, including DSM, increases in energy efficiency, distributed generation or underwater cables[1], is a practicable alternative to the Proposed Project. See also June 23, 2015 DVP Responses to ACOE Questions Received June 25, 2015; August 14, 2015 Courtney Fisher Letter to Tom Walker Responding to Walker Letter of July 31, 2005; September 23, 2015 Email to Randy Steffey Responding To Question Regarding 500 kV Vancouver Underwater Line; October 1 White Paper; November 13, 2015 Courtney Fisher Letter to Randy Steffey Responding To Statements At Public Hearing Regarding Underwater 345 kV Lines, Neptune and Hudson River Underwater Line and High Tension, Low Sag Conductors.

The SCC proceeding also produced evidence refuting the Comments' unsupported claims (pages 9, 29-30) regarding impacts of the Proposed Project. The Comments acknowledge (page 9) that the requirements of Va. Code § 10.1 419 were observed through the SCC's consideration of impacts on the limited portion of the James River that is designated a "historic river" by that statute but merely disagrees with the result of that consideration. The Comments also offer (page 9) conclusory claims, without factual support, of adverse impacts on economic development, including on property values, recreation and navigation. However, the Comments do not acknowledge the testimony of numerous witnesses at the Corps' October 30 public hearing who support the Proposed Project because they understand the positive impact of reliable electric service on economic development in the NHRLA. Their testimony was consistent with the following finding of the SCC, based on the extensive impacts evidence in its proceeding:

> The Commission finds that the Proposed Project will support economic development in the Commonwealth by cost-effectively maintaining system reliability in a large part of the Commonwealth and adequately increasing transmission capacity. Given these benefits and the modern development existing along the route of the Proposed Project, the Commission cannot conclude that tourism in the Historic Triangle or economic development in the Commonwealth will be negatively impacted by the Proposed Project.

SCC Order issued November 25, 2013 in Case No. PUE-2012-00029, page 53.

[1] None of the submarine HVAC lines referenced in the table on page 29 of the Comments can provide even half of the transmission capacity required to meet the NERC Reliability Standards for the NHRLA upon retirement of Yorktown Units 1 and 2.

For all of the foregoing reasons, the NPCA/PERI Comments do not present any practicable alternatives to the Proposed Project.

Sincerely,

Bob McGuire
Director, Transmission Project Development and Execution

cc: Board of Supervisors, James City County

ATTACHMENT 1

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.

ATTACHMENT 2

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

environmental remediation area on the property," and "bisect[s] the property, which would make plans for development, especially plans for mixed use resort development, effectively impossible."[1171] BASF witnesses supported a James River crossing offered by Dominion Virginia Power as Variation 3, which would leave more BASF property available for development.[1172] During the hearing, BASF counsel offered additional variations for the James River crossing portion of Variation 3 that were designed to lessen the impact of the line on Carter's Grove.[1173] Eventually, these additional variations were distilled to Variation 4, which provided a viable river crossing and crossed the BASF property as proposed in Variation 3.[1174] Nonetheless, Dominion Virginia Power continues to oppose use of Variation 4 based on the impacts to Carter's Grove, and because of the necessity of acquiring an easement across property owned by the Authority.[1175] The BASF routing issues will be addressed in the BASF Routing section below.

NEED

As directed by § 56-46.1 B, "the Commission shall determine that the line is needed and that the corridor or route the line is to follow will reasonably minimize adverse impact on the scenic assets, historic districts and environment of the area concerned." Consequently, the discussion of need will begin with a review of NERC reliability standards, the load flow modeling and contingency analyses used to determine need, and the consequences of inaction. The Proposed Project and the Proposed Alternative Project will then be examined. This examination will include an assessment of the impact of the proposed projects on both the identified electrical need, and on the Commonwealth's historic, scenic and environmental assets. Similar examinations will also be made of each of the other options identified and studied in this proceeding, including: (i) the Proposed Alternative Project, (ii) various 230 kV transmission options, (iii) generation options, (iv) combinations of 230 kV transmission and generation, and (v) variations offered by James City County witness Whittier. After review of each of the above, other factors, such as cost and construction times will be addressed before recommendations are presented to the Commission.

NERC Standards

Pursuant to the federal Energy Policy Act of 2005, NERC's voluntary reliability standards became mandatory, subject to FERC oversight.[1176] Indeed, Dominion advised that utilities could be fined up to $1 million per day per violation if found to be in noncompliance.[1177] NERC has been designated by the Federal Energy Regulatory Commission ("FERC") as the Electric Reliability Organization for the United States.[1178] NERC's mandatory reliability

[1171] BASF Brief at 3-4.
[1172] Exhibit No. 46, at 8-9.
[1173] Tr. at 354-363; Exhibit No. 39.
[1174] Tr. 1470-77; Exhibit No. 97.
[1175] Dominion Virginia Power Brief at 110-12.
[1176] Pub. L. No. 109-85, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), codified at 16 U.S.C. 824 (o).
[1177] Dominion Virginia Power Brief at 11; Exhibit No. 23, Attached Appendix at 4.
[1178] *Id.* at 11-12; *Id.*

standards are applied to Dominion Virginia Power through PJM's RTEP process.[1179] Through the RTEP, PJM's transmission owning members, such as the Company, are directed to make transmission upgrades to address near-term needs within five years and assess long-lead time transmission options requiring a planning horizon of 15 years or more.[1180]

Company witness Nedwick testified that the NERC Reliability Standards require the identification of critical system conditions and assessment of system performance for system events that fall into the following four basic categories:

Category A – No Contingencies;

Category B – Event resulting in the loss of a single element;

Category C – Event(s) resulting in the loss of two or more (multiple) elements;

and

Category D – Extreme event resulting in two or more (multiple) elements removed or cascading out of service.[1181]

Mr. Nedwick stated that for each of Category A, B, and C events, the system is required to remain stable and that both thermal and voltage limits will remain within the Company's planning criteria.[1182] Dominion Virginia Power asserted that its transmission planning criteria was "established over 30 years ago, [and] has been found to be compliant with NERC Reliability Standards by NERC, FERC and the Commission."[1183]

Staff witness Chiles examined and accepted Dominion Power's planning criteria.[1184] Indeed, Mr. Chiles ultimately concluded that "[t]he technical analysis in this case supports the finding that there are NERC reliability violations that must be addressed in the 2015 and 2021 periods."[1185]

James City County questioned the Company's planning criteria, and asked the Commission to adopt less rigorous criteria, especially when considering alternatives to the Proposed Project.[1186] For example, James City County witness Whittier maintained that for the Independent System Operator ("ISO") New England, the planning criteria permits 100% thermal loading, where Dominion Virginia Power considers it a violation for Category B, if the thermal loading exceeds 94%.[1187]

1179 *Id.* at 12; *Id.* at 4-5.
1180 *Id.*; Exhibit No. 92, at 5.
1181 Exhibit No. 31, at 7-8.
1182 *Id.* at 8.
1183 Dominion Virginia Power Brief at 10; Nedwick, Tr. at 1293.
1184 Exhibit No. 79, at 5-7.
1185 Staff Brief at 8-9; Chiles, Tr. at 1082.
1186 James City County Brief at 25-26, 36.
1187 *Id.* at 25; Whittier, Tr. at 942; *See*, Exhibit No. 31, at 8.

As pointed out by Dominion Virginia Power, the Company's planning criteria has been accepted by this Commission for many years and in many cases, as well as by FERC and NERC. The more rigorous criteria used by Dominion Virginia Power reflects the rate of growth experienced in many of the areas served by the Company, the constraints in siting new facilities, and the sensitivity of some of the vital government and military installations. As Mr. Whittier observed, "[i]n my decades of being involved in forecasting, I've done that enough to know that seldom are we right."[1188] I find that the inherent uncertainties of forecasting several years into the future, coupled with the growth, constraints, and sensitivity of the Company's system, especially in the North Hampton Roads Load Area, support continued use of the Company's planning criteria for this case.

Load Flow Forecasts

None of the Respondents or Staff took issue with the load flow studies undertaken by Dominion Virginia Power in this proceeding. Both Staff witness Chiles and James City County witness Whittier performed load flow studies that corroborated the load flow studies undertaken by Dominion Virginia Power.[1189] Moreover, the Company's load flow studies were conducted over many months; incorporated PJM's 2011, 2012, and 2013 load forecasts; and all consistently showed that with the 2014 retirements of Yorktown Units No. 1 and 2, and with the 2014 retirements of Chesapeake Units No. 1 – 4, additional transmission or generation is needed for the North Hampton Roads Load Area beginning in June 2015. Even James City County conceded that some project is needed (although, to be fair, James City County argued that Dominion Virginia Power failed to prove the need for the Proposed Project).[1190]

In the first quarter of 2011, Dominion Virginia Power's initial studies projected that as a result of anticipated load growth for the North Hampton Roads Load Area, NERC reliability violations would begin to occur in the summer of 2019.[1191] These studies were based on the 2010 PJM Load Forecast and reflected no generation retirements.[1192]

In November 2011, Dominion Virginia Power announced the retirement of Yorktown Unit 1 and Chesapeake Units 1 and 2 by the end of 2014.[1193] In the first quarter of 2012, Dominion Virginia Power's load flow studies, based on the 2011 PJM Load Forecast, showed that with these retirements, NERC reliability violations were now projected to begin in the summer of 2015.[1194] In September 2012, the Company announced the retirement of Yorktown Unit 2, and conducted additional load flow studies based on the 2012 PJM Load Forecast.[1195] These load flow studies showed that the retirement of Yorktown Unit 2 increased the severity of the NERC reliability violations beginning in 2015.[1196]

[1188] Whittier, Tr. at 943.
[1189] Exhibit No. 79, at 16; Exhibit No. 68, at 14.
[1190] James City County Brief at 22.
[1191] Dominion Virginia Power Brief at 18; Exhibit No. 87, at 4.
[1192] *Id.*; *Id.*
[1193] *Id.* at 19; *Id.*
[1194] *Id.*; *Id.*
[1195] *Id.*; *Id.*
[1196] *Id.*; *Id.*

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 "base case" scenarios to provide a point of reference for what may happen if the Yorktown units are retired and no new transmission or generation is added. Company witness Nedwick reported that with no new transmission or generation, in the summer of 2015, NERC reliability violations, or overloads, were projected for the following facilities:[1197]

- Line #2113 (Lanexa-Waller)
- Line #2102 (Chickahominy-Waller)
- Line #214 (Surry-Winchester)
- Line #263 (Chuckatuck-Newport News)
- Line #209 (Waller-Yorktown)
- Line #285 (Waller-Yorktown)
- Suffolk 500-230 kV Transformer
- Line #34 (Lanexa-Yorktown)
- Line #99 (Peninsula-Whealton)
- Whealton 230-115 kV Transformer
- Shellbank 230-115 kV Transformer
- Line #234 (Whealton-Winchester)
- Line #261 (Newport News-Shellbank)
- Chickahominy 500-230 kV Transformer
- Lanexa 230-115 kV Transformer
- Line #292 (Yorktown-Whealton)
- Line #289 (Chuckatuck-Suffolk)
- Line #2076 (Birchwood-Northern Neck)

Mr. Nedwick summarized the NERC reliability violations for 2015 for the base case as follows:[1198]

	NERC Category Tests			
Study	Category A	Category B	Category C	Category D
Study 1 – No Critical System Condition	0	39	350	21
Study 2 – Surry Unit 2 is the Critical System Condition	0	62	N/A	N/A
Study 5 – Surry Unit 1 as the Critical System Condition	1	93	N/A	N/A

The study results for 2021, show that the NERC reliability violations for the base case generally increase in number:[1199]

1197 Exhibit No. 90, at 5.
1198 *Id.* at 14.
1199 *Id.*

Study	NERC Category Tests Category A	Category B	Category C	Category D
Study 8 – No Critical System Condition	0	55	559	43
Study 9 – Surry Unit 2 is the Critical System Condition	0	49	N/A	N/A
Study 12 – Surry Unit 1 as the Critical System Condition	0	184	N/A	N/A

Dominion Virginia Power maintained that the consequences of the NERC reliability violations include: (i) the possibility of fines of up to $1 million per day per violation; and (ii) the risk of cascading outages for the North Hampton Roads area, Northern Virginia, the City of Richmond, and North Carolina.[1200]

All of the load flow studies conducted by Dominion Virginia Power were verified by Staff's independent consultant, John Chiles.[1201] Staff agreed with Dominion Virginia Power, that with the retirement of either Yorktown unit, NERC reliability violations will occur, beginning in 2015.[1202] Mr. Chiles further interpreted the load flow studies as follows:

> The problem . . . that we see from the power flow is . . . we have a set of lines coming in from the north, . . . from Chickahominy, . . . [and] 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.[1203]

Proposed Project[1204]

Dominion Virginia Power asserted that the Proposed Project

> will resolve all of the identified NERC Reliability Violations in 2015, and address the risk of cascading outages, by 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, by relieving loading on that system through the addition of a new 230

[1200] *Id.* at 10; Dominion Virginia Power Brief at 11, 14.
[1201] Staff Brief at 8; Chiles, Tr. at 1069.
[1202] *Id.*; *Id.*
[1203] *Id.*; *Id.* at 1109.
[1204] For a description of the Proposed Project *see, supra* at p.12. For a detailed description of the route to be followed by the Proposed Project *see, supra* at pp. 24, 25, 30, and 35.

kV source into the Peninsula east of Skiffes Creek, and by feeding existing east-west 230 kV and 115 kV lines that will be split to receive power from Skiffes [Creek Switching] Station.[1205]

Company witness Nedwick presented the results of the updated load flow studies directed in the *January 30 Ruling* for the Proposed Project, which confirmed that it would resolve all of the NERC reliability violations for 2015.[1206] For 2021, the updated load flow studies showed two NERC reliability violations (both Category C, with no critical system condition).[1207] Mr. Nedwick testified that the Proposed Project with "a minor upgrade of a 115 kV line in the area (a variation of which shows up in all the alternatives in that timeframe) . . . continues to resolve the identified NERC Reliability Violations."[1208] These results were verified and confirmed by Staff witness Chiles.[1209] No respondent challenged the results of the Company's load flow studies or the effectiveness of the Proposed Project to resolve identified NERC Reliability Violations.

However, as outlined above, James City County takes the position that the Proposed Project should not be approved because of its impacts on historic, scenic, and environmental assets.[1210] Specifically, James City County contends that the Proposed Project will cause significant adverse impact to the historic assets within the Historic Triangle, and will cause significant adverse impact to a largely unspoiled and historic portion of the James River.[1211] Dominion Virginia Power, on the other hand, maintains that views of the Proposed Project will be distant or, in most cases, not at all visible from the Historic Triangle, and that much of this portion of the James River is zoned industrial, with modern structures visible throughout the area.[1212] Both James City County and Dominion Virginia Power, rely in part upon visual simulations, which were the subject of much debate during the course of the April Hearing. Thus, the discussion of the impacts of the Proposed Project will focus first on the visual impacts of the Proposed Project on the Historic Triangle, to be followed with an examination of the visual impacts of the Proposed Project on this area of the James River.

Impact on the Historic Triangle – James City County presented several witnesses to establish the importance of the Historic Triangle, including Mr. Campbell, Dr. Horn, and Dr. Kelso. On brief, James City County pointed to the testimony of Dr. Horn and contended that "[t]he 23 miles between the sites of Jamestown, Yorktown, and Williamsburg represent . . . the 'alpha and omega of the British Empire.'"[1213] James City County also quoted Dr. Kelso's description of the Historic Triangle as "the kernel of what the United States finally became, in one place, 200 years of history."[1214] Dominion Virginia Power offered witnesses that attempted

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1205 Dominion Virginia Power Brief at 24; Exhibit No. 30, at 5.
1206 Exhibit No. 90, at 15.
1207 *Id.*
1208 Exhibit No. 87, at 12.
1209 Chiles, Tr. at 1071.
1210 James City County Brief at 1.
1211 *Id.* at 10-19.
1212 Dominion Virginia Power Brief at 61-68.
1213 James City County Brief at 10; Horn, Tr. at 636.
1214 *Id.*; Kelso, Tr. at 880.

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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

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[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	Category A	Category B	Category C	Category D
	NERC Category Tests			
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

[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.

ATTACHMENT 3

COMMONWEALTH OF VIRGINIA **131130149**

STATE CORPORATION COMMISSION

SCC-CLERK'S OFFICE
DOCUMENT CONTROL CENTER

AT RICHMOND, NOVEMBER 26, 2013

2013 NOV 26 P 1: 44

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY
d/b/a DOMINION VIRGINIA POWER

CASE NO. PUE-2012-00029

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

ORDER

On June 11, 2012, Virginia Electric and Power Company d/b/a Dominion Virginia Power ("Dominion" or "Company") filed with the State Corporation Commission ("Commission") an application for approval and certification of an electric transmission project, or for approval and certification of an alternative transmission project ("Application"). Dominion's proposed project and its proposed alternative project are described in turn below.

In its Application, Dominion proposed to construct: (a) approximately 7.4 miles of new overhead 500 kilovolt ("kV") electric transmission line from the Company's existing 500 kV-230 kV Surry Switching Station in Surry County to a new 500 kV-230 kV-115 kV Skiffes Creek Switching Station in James City County ("Surry-Skiffes Creek Line");[1] (b) the Skiffes Creek Switching Station; (c) approximately 20.2 miles of new 230 kV line, in the Counties of James City and York and the City of Newport News, from the proposed Skiffes Creek Switching Station to the Company's existing Whealton Substation located in the City of Hampton ("Skiffes Creek-Whealton Line"); and (d) additional facilities at the existing Surry Switching Station and Whealton Substation. The Surry-Skiffes Creek Line, the Skiffes Creek Switching Station, the

[1] In September 2012, Dominion filed supplemental testimony estimating the length of its proposed route at 8.0 miles. *See, e.g.*, Ex. 38 (Harper supplemental direct).

> (2) The estimated additional cost of placing the proposed line, in whole or in part, underground does not exceed 2.5 times the cost of placing the same line overhead, assuming accepted industry standards for undergrounding to ensure safety and reliability. If the public utility, the affected localities, and the State Corporation Commission agree, a proposed underground line whose cost exceeds 2.5 times the cost of placing the line overhead may also be accepted into the pilot program; and
>
> (3) The governing body of each locality in which a portion of the proposed line will be placed underground indicates, by resolution, general community support for the line to be placed underground.[23]

House Bill 1319 further provides that "[p]ublic utility companies granted a certificate of public convenience and necessity for a proposed transmission line not included in this program or not otherwise being placed underground shall seek to implement low-cost and effective means to improve the aesthetics of new overhead transmission lines and towers."[24]

Finally, Dominion requests a Commission determination that, based on the facts and circumstances of this case, the Skiffes Creek Switching Station constitutes a "transmission line" for purposes of Code § 56-46.1 F, which provides that "[a]pproval of a transmission line pursuant to this section shall be deemed to satisfy the requirements of § 15.2-2232 and local zoning ordinances with respect to such transmission line."

SYSTEM NEED

A series of load flow studies was introduced as evidence in this proceeding and evaluated by load flow study experts who testified as witnesses in this case. These studies demonstrate that the North Hampton Roads Area needs a significant electric system upgrade soon to maintain adequate reliability.

[23] 2008 Va. Acts ch. 799, Enactment 1, § 4, as extended by 2011 Va. Acts. ch. 244, Enactment 1.

[24] *Id.* at § 10.

The electric transmission system of Dominion and other public utilities is studied continually to assess its reliability in the near-term and long-term future. As a member of PJM Interconnection, LLC ("PJM"), a regional transmission organization,[25] Dominion does not assess the reliability of its transmission system only on its own. Through PJM's planning process, Dominion's transmission system is evaluated and planned as part of a 13-state region.[26]

Central to transmission system planning are load flow modeling studies that simulate system conditions to identify, among other things, projected overloads on the system.[27] These engineering studies assess whether the transmission system complies with NERC reliability standards, which are established for the important purpose of ensuring that the transmission system remains reliable so that customers' needs for electric service can be met.[28] Federal law enacted in 2005 made compliance with federal electric reliability standards mandatory, with violations by utilities carrying fines of up to $1 million per day.[29]

Dominion filed in this proceeding a number of load flow studies, allowing interested parties and our Staff to analyze the inputs and results of those studies.[30] As Staff points out, because reliability violations in the North Hampton Roads Area "are identified by a number of different models examining a number of different future years, the evidence supporting a system

[25] The term "regional transmission organization" is synonymous with the term "regional transmission entity" used in Section 56-579 of the Code of Virginia, which required Dominion to transfer the management and control of its transmission assets to such an entity, subject to Commission approval.

[26] Hearing Examiner's Report at 129-31.

[27] As explained by Staff, overloads exist when "under certain conditions, electrical flow on various transmission lines will exceed the power levels those lines are designed to accommodate, which can result in a failure of the lines." Staff's Post-Hearing Brief at 8.

[28] Tr. 631 (Reidenbach) (agreeing that reliable electric service is important to James City County's "sustainable future going forward").

[29] Hearing Examiner's Report at 129-30.

[30] To assist in its investigation of the Application, Staff retained the services of a consultant with expertise conducting load flow studies. *See, e.g.*, Ex. 79 (Chiles) at 1-2.

need does not rely on any single set of assumptions."[31] Notwithstanding the different assumptions used in the many load flow modeling studies analyzed in this case, the various load flow studies consistently reveal a significant system need in the area.

Dominion testified that it initially conducted load flow modeling studies indicating that normal load growth in the North Hampton Roads Area would result in reliability violations by 2019.[32] Those initial studies were analyzed and verified by our Staff.[33]

Importantly, the studies showing a need in 2019 were conducted *before* Dominion determined that six local generation units – two at the Yorktown Power Station and four at the Chesapeake Power Station – would be retired as a result of stricter federal environmental regulations, including the Mercury Air Toxics Standard ("MATS Rule").[34] Subsequent studies that included the impact of the generation retirements at these power stations showed that the retirement of only one unit at Yorktown was enough to cause reliability violations to begin in the summer of 2015.[35] Updated and supplemental studies directed by the Hearing Examiner and verified by Staff, confirm reliability violations occurring in the summer of 2015. For example, updated studies identify reliability violations or overloads projected to occur in 2015 on more

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[31] Staff's Post-Hearing Brief at 9-10. As recognized by Staff, these load flow models included different projected peak loads and different assumptions about both generation and transmission topology. *Id.* at 9.

[32] Ex. 31 (Nedwick direct) at 11.

[33] *See, e.g.*, Ex. 79 (Chiles) at 11-16. Although Staff raised a concern about one scenario from the studies showing a 2019 need, Staff was able to replicate and verify those modeling results, and the Company addressed this scenario in rebuttal testimony. *See, e.g.*, Ex. 87 (Nedwick rebuttal) at 24-25; Ex. 79 (Chiles), Attached Exhibit JWC-2 at 2.

[34] *See, e.g.*, Ex. 87 (Nedwick rebuttal) at 4; Ex. 110 (Kelly rebuttal); Ex. 103 (Faggert rebuttal). As discussed below, retaining generation at these facilities is not a reasonable alternative to addressing the identified needs of the North Hampton Roads Area.

[35] *See, e.g.*, Ex. 23 (Application), Attached Appendix at 72, 78-81; Ex. 87 (Nedwick rebuttal) at 4, n.1.

than a dozen transmission lines and several transformers on Dominion's transmission system.[36] These projected overloads are widespread in the North Hampton Roads Area.[37]

Consistent with NERC standards, the load flow studies discussed in the preceding paragraph involved stressing Dominion's transmission system under scenarios where one or two transmission circuits and one generation unit are unavailable.[38] NERC reliability standards also require testing for more extreme system conditions, including a scenario where all transmission lines located in a single right-of-way corridor and one generation unit are unavailable. The result of this analysis shows outages cascading into northern Virginia, the City of Richmond, and North Carolina.[39]

James City County, Save the James, and JRA have suggested that transmission planning in the Commonwealth should be undertaken in a less rigorous manner than has been the past practice of the Commission.[40] The record does not support taking transmission planning in such a direction. The North Hampton Roads Area is already a "load pocket" relying significantly on transmission to deliver generation from other areas of the Commonwealth.[41] This reliance will grow substantially with the upcoming retirements of two generation units at the Yorktown Power Station. At that time, the only remaining generation on the Peninsula will be a third unit at the

[36] *See, e.g.*, Ex. 90 at 5.

[37] *Id.*

[38] As described in the record, overloads resulting from such conditions are referred to as "Category A", "Category B", and "Category C" violations. *See, e.g.*, Ex. 31 (Nedwick direct) at 7-9.

[39] *See*, e.g., Ex. 23 (Application), Attached Appendix at 32-33, 43-45. For this reason, adding an additional line to this same corridor presents an unreasonable reliability risk. *See, e.g.*, Ex. 31 (Nedwick direct) at 10-11.

[40] *See, e.g.*; James City County's, Save the James's, and JRA's Joint Post-Hearing Brief at 25-26.

[41] *See, e.g.*, Ex. 89; Tr. 1074 (Chiles); Tr. 947 (Whittier).

Yorktown Power Station, which is subject to environmental restrictions that will severely limit its operation until its retirement.[42]

The Commission is greatly concerned about the widespread nature of the projected NERC reliability violations that are supported by the record of this case and that so many violations are projected to occur as early as 2015. The load flow modeling evidence, which has been verified by our Staff,[43] establishes a clear need for significant new electric infrastructure to address fast-approaching reliability violations projected for Dominion's transmission system. With a system need clearly established, we next turn to potential alternatives for satisfying the identified need.

ALTERNATIVES

The parties and Staff presented numerous potential alternatives for addressing the significant and uncontested system needs identified by the record. Those alternatives include generation, demand-side management, lower voltage transmission, underground transmission, transmission in different locations, and combinations of generation and transmission. While some alternatives warranted – and received – considerable evaluation, others are more conceptual or possess glaring shortcomings. However, our decision in this proceeding has been reached only after consideration of all potential alternatives, many of which are addressed below. Additionally, the Commission has considered all relevant factors supported by record evidence for each alternative.

[42] *See, e.g.*, Ex. 31 (Nedwick direct) at 12-13; Ex. 110 (Kelly rebuttal) at 8, 15; Ex. 103 (Faggert rebuttal) at 14-15.

[43] *See, e.g.*, Ex. 79 (Chiles); Tr. 1068-74.

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[42] *See, e.g.*, Ex. 31 (Nedwick direct) at 12-13; Ex. 110 (Kelly rebuttal) at 8, 15; Ex. 103 (Faggert rebuttal) at 14-15.

[43] *See, e.g.*, Ex. 79 (Chiles); Tr. 1068-74.

In summary, the Commission finds, based on the record, that none of the alternatives other than new transmission at 500 kV that were explored in this proceeding reasonably meet the reliability need identified in this case.

Generation Alternatives

As supported by the record and discussed below, generation alternatives are not a reasonable alternative to a transmission solution for addressing Dominion's upcoming system need. Some of the generation alternatives identified in this proceeding are largely conceptual or hypothetical. Certain generation alternatives introduced or studied by case participants do not correspond to any actual generation project currently under development or which could be developed in time and at the scale necessary to ensure the electric system remains reliable for a large portion of the Commonwealth.[44] We find that while some of this evidence further informs the magnitude of the challenge facing Dominion and its customers in the affected area,[45] the more conceptual generation presented in the record of this proceeding does not identify a reasonable alternative to a transmission solution.

For example, Environmental Respondents asserted that distributed solar resources (or distributed solar combined with demand-side management resources[46]) could satisfy the projected reliability criteria violations in the North Hampton Roads Area and could do so in the

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[44] PJM testified that its interconnection queue – which developers of generation must clear before connecting to Dominion's transmission system – does not currently contain any generation interconnection requests that would potentially offset the need for the Proposed Project. Ex. 92 (Herling rebuttal) at 22.

[45] *See, e.g.*, Ex. 79 (Chiles), Attached Exhibit JWC-2 at 13-15 (studying additional generation in the location of the proposed Skiffes Creek Switching Station while recognizing that location is not currently under active development for electric generation or the natural gas infrastructure necessary for such generation); Environmental Respondents' Post-Hearing Brief at 14-17 (distributed solar and demand-side management resources); James City County's, Save the James's, and JRA's Joint Post-Hearing Brief at 26 (liquified natural gas generation).

[46] Demand-side resources, and planning concerns about such resources, are discussed below. The planning concerns identified by record evidence are relevant to a consideration of these resources either as a stand-alone alternative or as part of alternative concepts that combine demand-side resources with other resources.

most cost-effective manner.[47] This assertion fails to appropriately recognize the magnitude of the projected reliability criteria violations made more imminent by significant generation retirements and operational restrictions resulting from environmental regulations. Although the Environmental Respondents cite to our recent approval of a distributed solar program through which Dominion will construct or facilitate up to 30 megawatts of distributed solar,[48] that 30 megawatts of nameplate capacity – even if all located in the North Hampton Roads Area – does not approach the size needed to address the reliability need identified in this case.[49] Nor do the Environmental Respondents substantiate their claim that solar resources are currently cost-effective.

Similarly, the record does not support suggestions by James City County that offshore wind or liquefied natural gas generation could satisfy the fast-approaching reliability criteria violations in the North Hampton Roads Area. Because these types of projects are exceptionally complex and, in some respects, may represent uncharted territory for developers,[50] the risk that such generation will be unavailable to address a need arising as soon as 2015 is too great to warrant further consideration in the instant case.

Based on the record, including the impending generation retirements and operating restrictions at the Yorktown and Chesapeake Power Stations, a more concrete approach to

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[47] *See, e.g.*, Environmental Respondents' Post-Hearing Brief at 14-17.

[48] *Application of Virginia Electric and Power Company, For approval of a Community Solar Power Program and for certification of proposed distributed solar generation facilities pursuant to Chapter 771 of the 2011 Virginia Acts of Assembly and §§ 56-46.1 and 56-580 D of the Code of Virginia*, Case No. PUE-2011-00117, 2012 S.C.C. Ann. Rept. 328, Order (Nov. 28, 2012).

[49] Studies were conducted in this case for the specific purpose of calculating how much generation would be needed to address projected reliability violations. *See, e.g.*, Ex. 90 at Rebuttal Schedule 4.

[50] *See, e.g.*, Tr. 1622-27 (identifying challenges and cost associated with obtaining a permit, constructing, and operating a liquefied natural gas import facility in a populated area like Yorktown); Tr. 1853 (describing the current construction cost of offshore wind).

addressing the needs of electric customers in the North Hampton Roads Area is required. To be clear, we appreciate that participants in this case have sought alternative solutions to addressing the identified system needs. However, for us to discharge in this case the responsibility delegated to us by the General Assembly, the Commission must identify those alternatives that may address identified system reliability needs and reasonably minimize adverse impact on scenic assets, historic districts, and the environment.

Although located outside of the North Hampton Roads Area, another potential generation alternative evaluated in this proceeding was generation in Brunswick County, Virginia. The addition of generation in Brunswick County is not a hypothetical, as the Commission recently approved the construction of a generation station in this location.[51] However, the load flow results show that the generation project in Brunswick County will not address the identified system needs of the North Hampton Roads Area.[52] Therefore the Brunswick County generation station is not a reasonable alternative in this case.

Other generation alternatives presented in this proceeding involve the potential retrofitting with additional emissions control equipment or the potential refueling, with natural gas, of generation units at the Yorktown and Chesapeake Power Stations.[53] Although some comparative environmental benefits can accrue from retaining infrastructure at a location with existing operations (and impacts), there can also be negative environmental impacts. The Environmental Respondents have, in prior proceedings, advocated that units at these stations

[51] *Application of Virginia Electric and Power Company, For approval and certification of the proposed Brunswick County Power Station and related transmission facilities pursuant to §§ 56-580 D, 56-265.2, and 56-46.1 of the Code of Virginia, and for approval of a rate adjustment clause, designated Rider BW, pursuant to § 56-585.1 A 6 of the Code of Virginia,* Case No. PUE-2012-00128, Doc. Con. Cent. No. 130810071, Final Order (Aug. 2, 2013).

[52] Ex. 81; Tr. 1077-80 (Chiles).

[53] As discussed herein, these options have been considered both on a stand-alone basis and in combination with other infrastructure upgrades.

should be retired.[54] The Environmental Respondents continued those efforts in the instant proceeding.

The evidence in this case – which includes, but is not limited to, environmental considerations – supports our finding that retrofitting or refueling options cannot address the identified NERC reliability violations in a cost-effective manner.[55]

With respect to the option of retrofitting coal-fired units at the Yorktown and Chesapeake Power Stations with additional environmental equipment, the Commission finds that the risks and costs associated with such an option are too great based on the record. Retrofitting these units would require several very large capital expenditures because the units would need a significant amount of additional equipment to continue coal and oil operations and comply with existing and anticipated environmental regulations.[56] The evidence in this case indicates that such capital expenditures total many hundreds of millions of dollars and could well exceed one billion dollars.[57] Additionally, the compliance costs evaluated in this case do not reflect other risks attendant to coal and oil generation, such as the current uncertainty regarding future regulation of carbon dioxide at the federal level.[58] Moreover, load flow studies analyzed in this

[54] Environmental Respondents' March 1, 2013 Motion Seeking Leave To File a Notice of Participation Out of Time at 2.

[55] *See, e.g.*, Ex. 110 (Kelly rebuttal); Tr. 1600-10 (Kelly); Ex. 79 (Chiles), Attached Exhibit JWC-3 at 6-7, and Attached Exhibit JWC-5.

[56] Tr. 1600-06 (Kelly). As the Hearing Examiner recognized, "Mr. Kelly confirmed that to retrofit Yorktown Units 1 and 2 to comply with environmental regulations would require the installation of a Dry Scrubber, Baghouse, Selective Catalytic Reduction, Water Intake Screens, Variable Speed Drives, and Closed Cycle Cooling." Hearing Examiner's Report at 118.

[57] Ex. 79 (Chiles), Attached Exhibit JWC-3 at 6-7, and Attached Exhibit JWC-5; Ex. 110 (Kelly rebuttal) at 20-23.

[58] We recognized these risks in a recent proceeding. *Application of Appalachian Power Company, For approval of transactions to acquire interests in the Amos and Mitchell generation plants and to merge with Wheeling Power Company*, Case No. PUE-2012-00141, Doc. Con. Cent. No. 130730256, Order at 8-9 (July 31, 2013) (citing Presidential Memorandum of June 25, 2013, Power Sector Carbon Pollution Standards, 78 Fed. Reg. 39,535 (2013)).

case indicate that assuming the additional cost and risk identified herein would only temporarily delay the need for system reinforcements in the North Hampton Roads Area.[59] For these reasons, the Commission finds, based on the record, that retrofitting Yorktown or Chesapeake generation units is not a reasonable alternative for ensuring transmission system reliability for Dominion's customers.

Another option explored in substantial depth by Dominion and other case participants involved the repowering or refueling of generation at the Yorktown or Chesapeake Power Stations with natural gas. The record contains gas transportation cost data obtained by Dominion from natural gas industry participants in response to requests by the Company in 2010, 2011, and 2012 for such information.[60] This data reveals that, similar to the retrofit option, the cost of extending a natural gas pipeline into the Hampton Roads area significantly exceeds the cost of transmission line alternatives.[61] This option becomes even more uneconomic with the capital cost that would be required at the Yorktown and Chesapeake Power Stations in order to generate electricity using natural gas from any such pipeline extension.[62] Staff also concluded, based on a review of this information and research, that "it does not appear that natural gas pipeline capacity could be constructed in time to meet the fuel requirements for repowered units at Chesapeake or Yorktown."[63] Accordingly, the Commission finds that repowering units at Yorktown and Chesapeake is not a reasonable alternative for ensuring transmission system reliability.

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[59] As discussed above, even without retirements at the Yorktown and Chesapeake Power Stations, reliability violations are projected to occur beginning in 2019 in the North Hampton Roads Area.

[60] *See, e.g.*, Ex. 79 (Chiles) at 31, and Attached Exhibit JWC-3 at 2-4.

[61] *Id.*, Attached Exhibit JWC-3 at 2-4, 8; and Attached Exhibit JWC-5.

[62] *Id.*, Attached Exhibit JWC-3 at 4.

[63] *Id.*, Attached Exhibit JWC-3 at 3-4.

A combination of retrofitting or repowering at the Yorktown or Chesapeake Power Stations and installing an electric transmission line alternative in this case does not yield a conclusion different from our consideration of these generation alternatives without transmission. A transmission line obviously does not address the natural gas pipeline constraints into the North Hampton Roads Area or environmental regulations that will not allow Dominion to continue operating the Yorktown and Chesapeake Power Stations in the same manner as in the past. These significant generation limitations, as well as the cost and time associated with alternative transmission components, make the cost and risk of the combination generation and transmission alternatives excessive, regardless of which transmission line alternative is chosen.[64]

In summary, while the Commission does not prejudge whether additional generation in the North Hampton Roads Area (or other concepts or projects discussed herein) may be reasonable at some point in the future, the record in this case does not support such generation as a reasonable alternative to a transmission solution for the area's significant transmission system needs appearing in 2015.

Demand-Side Resources

The Commission finds that demand-side resources, such as demand-side response and energy efficiency measures, were appropriately considered in this proceeding. The record supports the Hearing Examiner's conclusion that "additional amounts of [demand-side resources] should not be assumed to be available to address projected NERC reliability violations."[65]

The PJM load forecasts incorporated in Dominion's load flow modeling studies include demand-side resources that have cleared a three-year forward capacity auction conducted by

[64] *See, e.g.*, Ex. 87 (Nedwick rebuttal) at 13-14; Ex. 91 at Rebuttal Schedule 5.

[65] Hearing Examiner's Report at 150.

PJM.[66] In this case, James City County and the Environmental Respondents have asserted that the Commission should allow for more projected, and unspecified, demand-side resources to be considered.[67] In contrast, Staff has suggested that "[i]f anything, the evidence appears to support relying less on such resources for planning purposes."[68]

The Commission declines to alter, in this case, the extent to which projected levels of demand-side resources are incorporated in the planning studies that are conducted to ensure the Commonwealth's transmission system remains reliable. As recognized by PJM, the fact that a resource clears an auction for three years into the future does not mean that such a resource will, in fact, be available in that future year.[69] PJM's Vice President of Transmission Planning testified in this proceeding that a significant percentage of demand-side resources that clear PJM's auctions have recently been observed "buying out" of their obligations and he expressed concern that PJM may be "over-relying on demand response."[70] Given this testimony, the Commission does not find it reasonable in this case to impute additional demand-side resource amounts above and beyond those of the PJM forecasts.

The Commission further notes that, as Staff recognizes, the record in this case "indicates that a very significant – if not extraordinary – amount of demand-side response would be required in the North Hampton Roads area to avoid construction" of either a 500 kV transmission project or a 230 kV transmission project combined with additional generation.[71] For example,

[66] *See, e.g.*, Ex. 92 (Herling rebuttal) at 11-12.

[67] *See, e.g.*, Ex. 68 (Whittier) at 6, 13-15; Environmental Respondents' Post-Hearing Brief at 15-17.

[68] Staff's Post-Hearing Brief at 23 (emphasis omitted).

[69] *See, e.g.*, Ex. 92 (Herling rebuttal) at 14-15.

[70] *Id.*

[71] Staff's Post-Hearing Brief at 22-23.

Staff indicates that, to address projected 2015 NERC reliability violations, "the demand-side equivalent of 620 [megawatts] needed for a 'stand-alone' generation option would be required in the North Hampton Roads load area, which has only approximately 2,000 [megawatts] of peak demand."[72]

However, the Commission finds PJM's testimony that planning studies may be over-relying on demand response raises concerns that warrant further evaluation in future transmission and generation certificate proceedings. Accordingly, Dominion is hereby directed to provide, in future transmission and generation certificate applications, more detailed analysis of demand-side resources incorporated in the Company's planning studies used in support of such applications.[73]

230 kV Transmission Alternatives

In addition to alternatives that included generation or demand-side resources, as discussed above, several transmission alternatives were presented in this proceeding. Dominion's existing 500 kV system stops at the doorstep of the North Hampton Roads Area, with the closest lines at that voltage running from the Chickahominy Substation and Septa Substations to the Surry Nuclear Power Station.[74] Presently, a number of 230 kV and 115 kV lines transmit power into and within the North Hampton Roads Area.[75] As such, it is logical that many of the transmission alternatives evaluated in this proceeding are potential additions to Dominion's existing 230 kV transmission system.

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[72] *Id.* at 22. *See, e.g.*, Ex. 87 (Nedwick rebuttal) at 11-12, Rebuttal Schedule 3.

[73] To the extent known by the Company, such information should include, for example, the locations and providers of demand-side resources included in the relevant planning studies.

[74] Ex. 23 (Application), Attached Appendix at 6, 117.

[75] *Id.*

James City County and Save the James have characterized a 500 kV transmission line as a "larger, more luxurious option [that] may need to be foregone in favor of a smaller, more economical product."[76] But this does not describe the choice before us. Based on the record, we find that 230 kV options would not ensure system reliability in the North Hampton Roads Area and that most, if not all, 230 kV options would actually cost more than the Proposed Project.

Case participants had the ability not only to evaluate the results of Dominion's load flow modeling, but also to add different types of projects to Dominion's models to assess the effectiveness of such projects in addressing projected NERC reliability violations. Our Staff first tested 230 kV options with the initial load flow models that Dominion used in support of its Application, and Staff filed its results in the pre-filed testimony of its engineering consultant.[77] Subsequently, the Hearing Examiner directed Dominion to conduct and file many additional and updated load flow models to test, among other things, 230 kV options.[78] The Hearing Examiner directed these further studies after receiving input from Dominion, Staff, James City County, and other case participants that then had the opportunity to evaluate the studies.[79] Finally, James City County conducted additional 230 kV analyses using the updated, supplemental load flow models directed by the Hearing Examiner.[80] Below we discuss, in turn, underground and overhead 230 kV options for the North Hampton Roads Area.

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[76] James City County's and Save the James's Joint Comments on Hearing Examiner's Report at 21.

[77] *See, e.g.*. Ex. 79 (Chiles) at 23-26, Attached Exhibit JWC-2 at 3-6, 10-14.

[78] *See, e.g.*, Hearing Examiner's Report at 7-8, 103-109.

[79] Shortly after Staff's testimony was filed, Dominion and Staff filed a motion to extend the procedural schedule for the purpose of conducting further studies and, in doing so, proposed a number of studies. After holding a prehearing conference, the Hearing Examiner directed that specific studies be conducted, including a study of an alternative identified by James City County witness Whittier. Hearing Examiner's Report at 7-8.

[80] Tr. 901-1014 (Whittier).

a. 230 kV Transmission Underground Alternatives

The feasibility of undergrounding, in whole or in part, a transmission line crossing the James River was the focus of much evidence in this case. Compared to overhead alternatives, underground transmission lines require much different construction and materials, which result in different construction durations and costs. Additionally, the design and capability of a line depend on whether it is overhead or underground. For example, engineering evidence in this case indicates that undergrounding a 500 kV transmission line is not technically viable,[81] meaning that undergrounding options must be at a lower voltage, such as 230 kV.

It is also important to understand that, when comparing transmission lines with different voltages (such as 500 kV and 230 kV), the difference in their voltages is not directly proportional to the difference in their capacities, measured in megavolt amperes ("MVA"), for delivering power. For example, the record in this case shows that the single-circuit 500 kV Surry-Skiffes Creek Line would provide approximately 4,300 MVA of capacity into the North Hampton Roads Area while an underground single-circuit 230 kV line that Dominion recently placed into service provides only 600 MVA of capacity.[82]

Compared to an overhead transmission line, an underground line can lessen or eliminate certain environmental impacts, including many visual impacts[83] and impacts associated with securing a transmission tower into the ground or a river bed.[84] Replacing the overhead 500 kV

[81] The record identifies only one location in the United States where 500 kV lines have been constructed underground. Those lines, which are short interconnections between generation at the Grand Coulee Dam and an adjacent switchyard, are in the process of being replaced with overhead lines due to reliability concerns. *See, e.g.*, Ex. 93 (Allen rebuttal) at 16, Rebuttal Schedule 3; Ex. 23 (Application), Attached Appendix at 58.

[82] *See, e.g.*, Ex. 79 (Chiles) at 24; Ex. 33 (Allen direct) at 3-4; Ex. 102 (Thomassen rebuttal) at 13-15, Rebuttal Schedule 8.

[83] *See, e.g.*, Ex. 83 (McCoy), Attached Exhibit WDM-1 at 19-21.

[84] *See, e.g.*, Ex. 93 (Allen rebuttal) at 15.

Surry-Skiffes Creek Line with an underground transmission line would, for example, lower the scenic impact on Carter's Grove; Kingsmill; the Captain John Smith National Historic Water Trail; Black's Point; parts of the Colonial Parkway; and other viewpoints on or around this portion of the James River. However, as discussed further in our evaluation of 500 kV alternatives herein, the Commission agrees with the findings and conclusions of the Hearing Examiner that the Proposed Project, with an overhead 500 kV crossing of the James River: (1) will have little visual impact on the Colonial Parkway or Jamestown Island; (2) will have greater visual impacts on sites such as Carter's Grove and Kingsmill; and (3) will not alter the current nature of the James River in the relevant area.[85] Accordingly, while the Commission does not find that the environmental impact of extending an overhead 500 kV transmission line from the Surry Switching Station to the industrial BASF property is as great as some of the participants contend in this case, all identified impacts have been considered and weighed.

The Commission also recognizes, however, that underground transmission lines and their construction are not without environmental impacts. Underground construction creates other types of environmental impacts, including those associated with boring underground or boring under a river bed and dredging a river bed to install splice pits.[86] Among other environmental impacts, Dominion estimated that an underground river crossing of the James River would result in a riverbed excavation of 36,000 cubic yards.[87] Comparing overhead construction to underground construction therefore requires a weighing of, among other things, the environmental impacts of each.

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[85] Hearing Examiner's Report at 134-40.

[86] *See also* Ex. 102 (Thomassen rebuttal); Tr. 1678-80 (Harper); Ex. 83 (McCoy), Attached Exhibit WDM-1 at 6-7; Tr. 1137 (McCoy).

[87] Ex. 93 (Allen rebuttal) at 15.

The Commission has carefully considered the relative impacts to historic resources, scenic assets, and other environmental considerations presented in this case. However, the factors that must be considered in this proceeding, as discussed above, are broad and are not limited only to environmental considerations. Based on the record, the Commission finds that the impediments associated with attempting to address the identified reliability violations in the North Hampton Roads Area by placing a transmission line underground outweigh competing environmental considerations. The Commission finds that underground alternatives do not reasonably meet the reliability need identified in this case.

Underground transmission projects are complex endeavors. The construction of an underground project can involve, among other things, significant horizontal drilling to install the pipes needed to contain underground electric cables, dredging large pits in the ground and the river bed to allow for underground electric cables to be spliced together, and constructing transition stations where the underground cable transitions to an overhead line.[88] Given the complexity of these projects, Staff noted that most of the recent underground transmission projects constructed by Dominion have experienced delays.[89]

Dominion testified that an underground crossing of the James River would require an estimated 48 months (single circuit) or 60 months (double circuit) to complete.[90] But the load flow studies in this case demonstrate significant reliability violations occurring the summer after Yorktown generation retires in response to environmental regulations that include an April 2015 deadline for compliance with the MATS Rule. Accordingly, even if Dominion successfully

[88] *See, e.g.*, Ex. 102 (Thomassen rebuttal).

[89] Staff's Post-Hearing Brief at 42.

[90] *See, e.g.*, Ex. 93 (Allen rebuttal) at 10; Tr. 1464-65 (Allen); Dominion's Comments on the Hearing Examiner's Report at 36-37.

defers reliability violations by obtaining a limited extension of the MATS Rule,[91] compliance with federal environmental regulation simply cannot be reconciled with the realities of underground construction. Additionally, even if an underground transmission line *could* be completed in time to address the need demonstrated in this case, the Commission finds, based on the record evidence, that such options would not be effective (much less cost-effective) or otherwise satisfy the requirements of Virginia law.

For example, substituting a single-circuit 230 kV underground transmission line for the proposed Surry-Skiffes Creek Line is estimated to cost approximately $273 million, or approximately $118 million more than the $155 million Proposed Project.[92] However, the load flow modeling studies in this case show that the underground line component of this more expensive project would, upon installation, be overloaded.[93] The Commission cannot find that the public convenience and necessity require what the evidence shows could be a useless, expensive project.[94]

The performance of a double-circuit 230 kV underground Surry-Skiffes Creek Line would be better than a single circuit because the line itself would no longer be overloaded upon installation. However, load flow studies show that a double-circuit 230 kV underground line

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[91] Dominion can request a one-year extension of this deadline from the DEQ and can request a second one-year extension, in the form of an enforcement Administrative Order, from the Environmental Protection Agency. *See, e.g.*, Hearing Examiner's Report at 154.

[92] *See, e.g.*, Ex. 91 at Rebuttal Schedule 5; Tr. 906-07 (Whittier) (testifying that overall the Company's construction costs are reasonable).

[93] *See, e.g.*, Tr. 1071-74 (Chiles); Ex. 90 at Rebuttal Schedule 4.

[94] Although this section of the Order discusses the total cost of projects or portions of projects, the record indicates that selecting a 230 kV project or the Chickahominy Alternative, rather than the 500 kV Proposed Project, would, under current federal regulation, increase the share of costs that PJM would assign to Virginia ratepayers. *See, e.g.*, Hearing Examiner's Report at 152; Staff's Post-Hearing Brief at 34-36; ODEC's Post-Hearing Brief at 8.

would not address projected overloads on one transmission line and one transformer.[95] This double-circuit option, which, at $440 million, is estimated to cost $285 million more than the Proposed Project, would still require additional infrastructure projects (with additional costs and impacts) to address projected reliability violations that the Proposed Project addresses.[96] Even if a project including a double-circuit 230 kV underground line could be completed in time to address upcoming NERC reliability violations, the Commission finds that the significant reliability and cost disadvantages of such a project, among other detrimental considerations, outweigh the beneficial considerations from constructing a double-circuit transmission line under, rather than over, the James River. The evidence demonstrates that this type of project would not reasonably meet the identified reliability need.

There are similar problems with the underground variation put forth by James City County that would combine a single-circuit 230 kV underground crossing of the James River with a special protection scheme of some unspecific type, among other components of this variation. This James City County underground variation is estimated by Dominion to cost approximately $146 million more than the Proposed Project[97] while James City County estimates it would cost $69 million more.[98] A James City County witness testified that a special protection scheme could be used to address one projected overload;[99] however, Dominion identified several transformers overloading with this variation.[100] Additionally, PJM's Vice President of

[95] *See, e.g.*, Tr. 1071-74 (Chiles); Ex. 90 at Rebuttal Schedule 4.

[96] Ex. 90 at Rebuttal Schedule 4; Tr. 906-07 (Whittier) (testifying that overall the Company's construction costs are reasonable).

[97] Ex. 95.

[98] Tr. 922 (Whittier).

[99] Tr. 937 (Whittier).

[100] Tr. 1298, 1303 (Nedwick).

Transmission Planning testified that PJM only allows special protection schemes as a temporary measure in its region and that one type of special protection scheme, a system reconfiguration, may not even be effective in the North Hampton Roads Area.[101] By relying on a conceptual special protection scheme and underground construction that is likely to extend beyond projected reliability violations, the Commission finds that this more costly variation presents an unreasonable reliability risk to customers that, among other factors, outweighs the beneficial considerations. Based on the evidence, the Commission finds that this alternative would not reasonably meet the reliability need identified in this case.

Another James City County 230 kV underground variation relies on a device known as a phase angle regulator ("PAR"). This alternative – which Dominion estimates would cost approximately $142 million more than the Proposed Project[102] and James City County estimates would cost $37 million more[103] – was offered without an engineering study to evaluate its performance.[104] James City County testified that PARs are commonly installed and contended that a 230 kV project with a PAR could potentially work.[105] Dominion testified that this James City County alternative was electrically comparable to a project that PJM previously studied and found deficient[106] and testified further that using a PAR on a dynamic network system "would be

[101] Tr. 1387-88 (Herling).

[102] Ex. 95.

[103] Ex. 69.

[104] Tr. 987 (Whittier).

[105] *See, e.g.*, Tr. 925 (Whittier); James City County's and Save the James's Joint Comments on Hearing Examiner's Report at 19-20.

[106] Tr. 1300, 1346 (Nedwick) ("[T]he analysis that was done for the LS Power proposal that the PAR was never able to have a setting capable of preventing itself from overloading and at the same time it was causing other devices to overload."). *See also* Ex. 92 (Herling rebuttal) at 20 ("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.").

at best . . . very problematic and potentially a detriment to reliability."[107] The Commission finds that, among other considerations, the reliability risk associated with this more costly underground alternative, which likely could not be constructed in time to address upcoming projected reliability violations and has been offered without study, outweighs the benefits associated with this option. Based on the evidence, the Commission finds that this alternative would not reasonably meet the reliability need identified in this case.

Although Dominion has not requested that the Proposed Project or any alternative thereof be included in the underground pilot program established by HB 1319, the Commission has nonetheless reviewed the criteria for potential inclusion in this program. Because, as discussed above, the Proposed Project and alternatives thereof are not viable for underground construction, none of the projects evaluated in this proceeding qualify for inclusion in the underground pilot program.[108]

b. 230 kV Transmission Overhead Alternatives

James City County proposed two overhead 230 kV alternatives that include, among other components, river crossings near the James River Tower Bridge.. Such projects would shift the environmental impacts associated with a river crossing downriver from where the Proposed Project is proposed to cross. Substantially different areas would be impacted by such projects.

The first such alternative, identified as Alternative C, was proposed in prefiled testimony. This alternative was ultimately abandoned by James City County after modeling studies

[107] Tr. 1346-47 (Nedwick). *See also* Ex. 92 (Herling rebuttal) at 20 ("Operationally, the 230 kV Surry-Skiffes Creek line and PAR, whether underground or overhead, is a challenging solution....").

[108] We therefore need not reach issues concerning the pilot program's other statutory criteria, including the cost criteria which Dominion asserts the underground alternatives also fail. *See, e.g.*, Ex. 93 (Allen rebuttal) at 19-20; Tr. 1454-55 (Allen).

indicated that it would not work electrically.[109] The record supports this conclusion and therefore Alternative C warrants no further consideration in this proceeding.[110]

The second proposed alternative with a downriver, overhead crossing of the James River was offered through oral testimony as a variation to the abandoned Alternative C ("Variation to Alternative C"). The primary components of Variation to Alternative C include a new transformer, rebuilding an existing transmission line, and constructing a new 230 kV transmission line between Dominion's existing Chuckatuck[111] and Whealton substations, which would require an overhead crossing of the James River.[112] James City County testified that its Variation to Alternative C did not address an overload on one transmission line[113] while Dominion testified that this alternative also produced multiple transformer overloads and "troubling" effects on the operations of the Surry Nuclear Power Station.[114]

In proposing Variation to Alternative C as an overhead project, James City County acknowledged that a portion of a new Chuckatuck to Whealton line might need to be undergrounded if the existing right-of-way is constrained.[115] The evidence in this case confirms this is a very constrained right-of-way, particularly in Newport News (*i.e.*, between the James River and the Whealton substation).[116] As with other alternatives discussed above, this project presents unreasonable reliability risks. Even if it could be constructed in a timely and safe

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[109] Tr. 939 (Whittier).

[110] *See, e.g.*, Ex. 90.

[111] The Chuckatuck substation is located in Isle of Wight County. Ex. 119; Tr. 1681 (Harper).

[112] Ex. 71.

[113] Tr. 941-45 (Whittier).

[114] Tr. 1303-04 (Nedwick).

[115] *See, e.g.*, Tr. 995 (Whittier).

[116] Tr. 1680-85 (Harper); Ex. 119.

fashion, Variation to Alternative C would leave unaddressed certain projected reliability violations. Additionally, the underground construction required in a populated area of Newport News for this alternative makes it highly unlikely that such a complex project could be constructed in time to address projected reliability violations. The Commission also recognizes that underground construction would cost ratepayers more.[117]

The significant reliability risk associated with Variation to Alternative C is comparable to many of the 230 kV alternatives with underground crossings of the James River. Although James City County estimates the cost of Variation to Alternative C to be closer to the Proposed Project than those other alternatives, so too are the environmental impacts. This is because Variation to Alternative C involves, among other things, both an overhead crossing of the James River and a lengthy underground construction project.

The Commission finds that, among other considerations, the significant reliability risks associated with Variation to Alternative C and the costs associated therewith outweigh the benefits from constructing this alternative instead of the Proposed Project. Based on the evidence, the Commission finds that this alternative would not reasonably meet the reliability need identified in this case.

In comments on the Hearing Examiner's Report, James City County and Save the James indicated that that James City County "was able to resolve many, but not all, NERC violation [sic]" with its variations, and that those variations "would work" with "more time and effort."[118] Such an assertion fails to appropriately recognize the considerable volume, quality, and weight

[117] Ex. 96. These estimates do not include any costs associated with addressing remaining reliability violations or operational problems resulting from Variation to Alternative C.

[118] James City County's and Save the James's Joint Comments on Hearing Examiner's Report at 19-20. James City County indicates that Dominion notified it of the Chickahominy Alternative Project and the Proposed Project in January and March of 2012, respectively. *Id.* at 28; Ex. 50 (Reidenbach) at 13.

of the engineering analysis of alternative projects included in the record. Indeed, the Hearing Examiner even directed Dominion to conduct and file load flow modeling analysis of a James City County variation,[119] which the County ultimately abandoned.[120] Additionally, the Commission concludes, based on the record, that maintaining reliability of the grid used to support electric service in the North Hampton Roads Area and complying with federal environmental regulations do not allow more time for studying hypothetical options. Significant projected reliability violations resulting from known environmental regulations require construction to commence as soon as possible.

Dominion's Application also identifies double-circuit overhead 230 kV variations of the Proposed Project and the Chickahominy Alternative Project. More specifically, the Application identifies, as one alternative, construction of the Proposed Project with a double-circuit 230 kV (instead of single-circuit 500 kV) Surry-Skiffes Creek Line and, as a second alternative, construction of the Chickahominy Alternative Project with a double-circuit 230 kV (instead of single-circuit 500 kV) Chickahominy-Skiffes Creek Line. Although the option was approximately $23 million less than the Proposed Project, Dominion rejected the 230 kV double-circuit Surry-Skiffes Creek Line because, among other things, it: (1) would not resolve all of the identified NERC criteria violations; (2) would require taller structures than a single-circuit 500 kV line; and (3) would limit potential future extensions of Dominion's transmission system to the south of the Surry Nuclear Power Station.[121] Dominion rejected the double-circuit 230 kV Chickahominy-Skiffes Creek line because it failed to address identified

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[119] *See, e.g.*, January 30, 2013 Hearing Examiner's Ruling at 2 (directing Dominion to model James City County's "Alternative C").

[120] Tr. 939 (Whittier).

[121] *See, e.g.*, Ex. 23 (Application), Attached Appendix at 55-56.

reliability criteria violations and would cost approximately $36 million more than the Proposed Project.[122] Based on the record, the Commission finds that these two alternatives, which no case participant supported, were reasonably rejected.

Because the evidence demonstrates that oncoming reliability violations cannot be reasonably addressed by generation alternatives (alone or in combination with transmission alternatives), demand side management alternatives, or lower voltage transmission (underground or overhead), we turn next to the 500 kV Proposed Project and the 500 kV Chickahominy Alternative Project.

<u>*500 kV Transmission Alternatives*</u>

Comparing the two electrically equivalent 500 kV projects proposed by Dominion, the Commission agrees with the Hearing Examiner that "the [Chickahominy Alternative Project] has a higher cost than the Proposed Project and will have a greater impact on scenic assets, historic districts and the environment."[123] Many public witnesses and case participants – including Dominion, the Ledbetters, Lennar, Charles City County, and Staff – introduced a considerable amount of comparative data, pictures, and other testimony that makes clear the comparative benefits of the Proposed Project.[124] The record does not support approval of the Chickahominy Alternative Project instead of the Proposed Project.

Because these two projects share many common components, their relative advantages and disadvantages stem from their use of different 500 kV lines: the approximately 8.0 mile-long Surry-Skiffes Creek Line of the Proposed Project and the approximately 37.9 mile-long Chickahominy-Skiffes Creek Line of the Chickahominy Alternative Project. The

[122] *See, e.g.*, Ex. 23 (Application), Attached Appendix at 56-57.

[123] Hearing Examiner's Report at 175.

[124] *See, e.g.*, Ledbetters' Post-Hearing Brief; Lennar's Post-Hearing Brief at 3-8; Staff's Post-Hearing Brief at 27-36.

much shorter Surry-Skiffes Creek Line is estimated to cost approximately $58 million less than the Chickahominy-Skiffes Creek Line.[125]

Based on information identifying certain environmental impacts that the Commission regularly assesses as part of our overall evaluation of transmission project impacts, the impacts associated with the Chickahominy Alternative Project were, almost across the board, numerically greater than for the Proposed Project.[126] For example, the Surry-Skiffes Creek Line of the Proposed Project passes within 500 feet of approximately 160 residences, while the Chickahominy-Skiffes Creek Line counts 1,129 residences within 500 feet of its route.[127]

The difference between the overall environmental impacts of these two projects only grows when one looks beyond the numbers for the few impacts that appear to weigh in favor of the Chickahominy Alternative Project. For example, variations of the James River crossing of the Proposed Project would involve a longer crossing of surface waters than the Chickahominy River crossing for the Chickahominy Alternative Project. Looking only at this statistic, one might conclude that a James River crossing would be more visually impacting than the Chickahominy River crossing. One might further conclude that, since both lines would cross the Captain John Smith National Historic Water Trail, the longer crossing of the James River would be a greater impact to a historic resource than the shorter crossing of the Chickahominy. But persuasive evidence supports a contrary finding. Namely, one of the experts retained by Staff highlighted (and other evidence supported) a stark difference between impacts already existing on the relevant portions of the James River but absent from those portions of the Chickahominy River. Staff testified that "there really is no comparison" between the two crossings because the

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[125] *See, e.g.*, Ex. 116 (Swanson rebuttal) at Rebuttal Schedule 1.

[126] *See, e.g.*, Hearing Examiner's Report at 142; Ex. 23; Ex. 29; Tr. 499 (Lake); Ex. 50 (Reidenbach) at 13-16.

[127] *Id.*; Ex. 83 (McCoy), Attached Exhibit WDM-1 at 23-24.

Chickahominy route would traverse a pristine area of the Captain John Smith National Historic Water Trail.[128]

In contrast, the James River route is already heavily impacted by more modern developments.[129] Such developments include the Surry Nuclear Power Plant, Kingsmill (including its marina), water towers, the Ghost Fleet,[130] and tall theme park rides – all of which are visible from this portion of the James River.[131]

The environmental impact of the Proposed Project is discussed in greater detail below in our evaluation of the Proposed Project under applicable law. In this regard, James City County and Save the James argue that even if need is established, the statute requires the Proposed Project to be denied if there is not a route that satisfies the environmental standards in the Code.[132] As discussed below, however, we have found based on the evidence in this case that the Proposed Project and the route approved herein meet the statutory environmental standards.

THE PROPOSED PROJECT

Need

The Proposed Project addresses significant near-term system needs in the North Hampton Roads Area while also addressing the area's longer-term needs.

As discussed above, the extensive load flow modeling results and analysis in this case demonstrate a significant system need projected to arise as early as 2015 and that the Proposed

[128] Tr. 1160-61 (McCoy). *See also* Ex. 63 (Street) at 9-11; Ex. 21 (Ledbetter).

[129] *See, e.g.*, Tr. 835-41 (Street).

[130] The Ghost Fleet is "a collection of retired naval vessels that are temporarily anchored offshore from Fort Eustis." Ex. 37 (Harper direct) at 14. *See also* Tr. 817 (Street).

[131] *See, e.g.*, Tr. 1136-37 (McCoy); Ex. 100; Ex. 118 (Harper rebuttal) at Rebuttal Schedules 1, 2.

[132] *See, e.g.*, James City County's and Save the James's Joint Comments on the Hearing Examiner's Report at 10-18.

Project, unlike other potential alternatives, will address that need.[133] Upcoming reliability violations have been projected under a variety of reasonable future scenarios that have been updated and expanded during the course of this case. The evidence in this case establishes that federal environmental regulation will soon affect the operation of generating facilities needed to maintain reliable electric service in the North Hampton Roads Area, but that the Proposed Project will complement existing infrastructure to maintain system reliability when these generation facilities are retired or significantly restricted.

Our approval herein is not a matter of "bigger is better;"[134] rather, we approve the Proposed Project because the evidence demonstrates that it is of the appropriate size, location, and design to address the significant reliability risks in the North Hampton Roads Area, and ensure the continued delivery of critically needed electric service to the hundreds of thousands of people in this region of Virginia. The evidence demonstrates that the public convenience and necessity require all components of the Proposed Project – including the 500 kV Surry-Skiffes Creek Line, the 230 kV Skiffes Creek-Whealton Line, and the Skiffes Creek Switching Station, which is a critical part of both these lines – to ensure reliability in the Commonwealth.

Because the Proposed Project is needed to address significant near-term reliability violations, our approval herein is based significantly on that urgent need. In addition to this urgent need, the Commission finds that the Proposed Project addresses longer-term system needs fundamental to ensuring reliability further into the future. Namely, the Proposed Project addresses reliability violations projected as early as 2019 due solely to continued load growth in the North Hampton Roads Area (*i.e.*, without consideration of upcoming generation retirements).

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[133] We agree with the Hearing Examiner that the record supports the continued use of Dominion's planning criteria, which has been accepted by this Commission for many years and in many cases, as well as by the Federal Energy Regulatory Commission and NERC. Hearing Examiner's Report at 129-31.

[134] James City County's and Save the James's Joint Comments on the Hearing Examiner's Report at 21.

Furthermore, the Commission agrees with the Hearing Examiner that an additional benefit of the Proposed Project is that it lowers the possibility "that this or nearby areas will be impacted by the need for additional transmission or generation."[135]

Scenic Assets, Historic Districts and Resources, and the Environment

The Commission recognizes the environmental impact that the Proposed Project will have on the Counties of James City, Surry, and York and the Cities of Newport News and Hampton. However, the Commission finds, based on the record, that the routes chosen for the Surry-Skiffes Creek Line and the Skiffes Creek-Whealton Line, and the use of an existing transmission corridor for the Skiffes Creek Switching Station, reasonably minimize adverse impact on the scenic assets, historic districts and resources, and environment in the area of the Proposed Project. Additionally, we adopt the DEQ recommendations identified below as conditions to our approval that we find, based on the record, are desirable or necessary to minimize adverse environmental impact.

The Proposed Project's more significant impacts to scenic assets, historic districts and resources, and the environment are associated with the 500 kV Surry-Skiffes Creek Line and specifically the portion of the line that crosses the James River. The Proposed Project will require the installation of towers and lines across the James River, but will do so in a part of the James River where the Commission finds that impacts to scenic assets, historic districts and resources, and the environment will be reasonable. The 3,000 mile-long Captain John Smith National Historic Trail, which includes the James River, possesses areas that are significantly developed.[136] As previously noted, visible already from the part of the James River where the

[135] Hearing Examiner's Report at 157.

[136] Tr. 831-32 (Street).