Surry-Skiffes Creek-Whealton 500 kV/230 kV Alternatives Analysis

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Executive Summary

Dominion Virginia Power (Dominion) is proposing the construction of a new overhead transmission line extending from the Surry Nuclear Power Plant in Surry County, Virginia to the Whealton Substation in the City of Hampton, Virginia. The project includes an overhead 500 kV line extending approximately 7.4 miles from the Surry Nuclear Power Plant to a proposed switching station to be constructed in James City County. From there the project continues for approximately 20.2 miles with the construction of an overhead 230 kV transmission line. Dominion submitted a Joint Permit Application to the U.S. Army Corps of Engineers (Corps) on August 8, 2013 detailing the purpose and need of the project, alternatives considered and avoidance and minimization measures. The Corps has subsequently requested additional information regarding the planning of the proposed project and alternatives considered by Dominion.

On behalf of Dominion, Stantec Consulting Services, Inc. (Stantec) is providing this additional information to the Corps for their review and consideration. The following document provides further detail regarding the purpose and need of the project, regulatory review and oversight of the project to date, and a more detailed alternatives analysis. As the 230 kV portion of the project is to be constructed within existing right-of-way and appears to have minimal impact on environmental and cultural resources, alternative routes for this portion of the project will not be reviewed in further detail in this document. The alternatives analysis presented herein focuses solely on the proposed 500 kV portion of the project which is currently routed as a new overhead crossing of the James River. This alternatives analysis will consider the No Action alternative, as well as offsite alternatives such as new generation, repowering of existing generation and use of alternative corridors. The ability to meet the purpose and need utilizing underground alternatives, lower voltage lines or a combination of generation and transmission alternatives is also evaluated.

1.0 Project Purpose and Need

The proposed Surry – Skiffes Creek – Whealton 500 kV/230 kV project (Project) was originally projected to be needed by 2019 to meet growing electric demands within the North Hampton Roads Load Area (NHRLA). However, in December 2011, the United States Environmental Protection Agency's (EPA) proposed Mercury Air and Toxics Standards (MATS) rule was rendered final. The MATS rule is designed by EPA to reduce the emission of toxic air pollutants from power plants and is specifically aimed at reducing emissions from new and existing coal- and oil-fired electric utility generating units. In light of this rule, Dominion evaluated its existing generation facilities to identify which units, if any, would be affected by the MATS rule. The results of this evaluation were presented in Dominion's 2011 Integrated Resource Plan (IRP). The plan, discussed in further detail below, identified Yorktown Unit 1 as being required to be retired no later than April 2015 to comply with the MATS rule. Yorktown Unit 2 was ultimately identified as being retired no later than April 2015 in the 2012 IRP. Dominion's power flow studies, confirmed by its Regional Transmission Operator, PJM Interconnection L.L.C. (PJM), show that with the retirement of *either* Yorktown Unit 1 or Unit 2, Dominion's transmission system will not meet NERC Reliability Standards without load shedding if the proposed project is not in service by the time the generating units retire. The purpose and need of the Project is to provide reliable, cost-effective bulk electric power delivery to the NHRLA to maintain compliance with NERC reliability standards. The project is the minimum necessary to address the immediate reliability issues directly resulting from the loss of generation.

Note that Dominion has applied for, and been granted, a one-year extension by the DEQ allowing Yorktown Units 1 and 2 to remain in service, resulting in a generation retirement and in-service target date of April 2016 for the Project. As such, while materials submitted to the State Corporation Commission (SCC) and PJM reference the original 2015 deadline, all alternatives considered herein will be discussed in relation to the April 2016 deadline. Any alternatives considered to be viable from an electrical, cost, environmental and cultural standpoint must also be able to be feasibly constructed within this timeframe for the alternative to meet the purpose and need.

2.0 Regulatory Oversight

The planning and operation of the high voltage electric grid is a complex task that requires extensive planning and oversight at the utility, state, regional and federal level. As a member of the Eastern Interconnection Transmission grid, Dominion is directly or indirectly connected with all transmission systems within the United States and Canada from the Rocky Mountains east to the Atlantic Coast (with the exception of Quebec and most of Texas). A reliable, functional electric grid is essential to the economic viability and security of the nation and the NHRLA region.

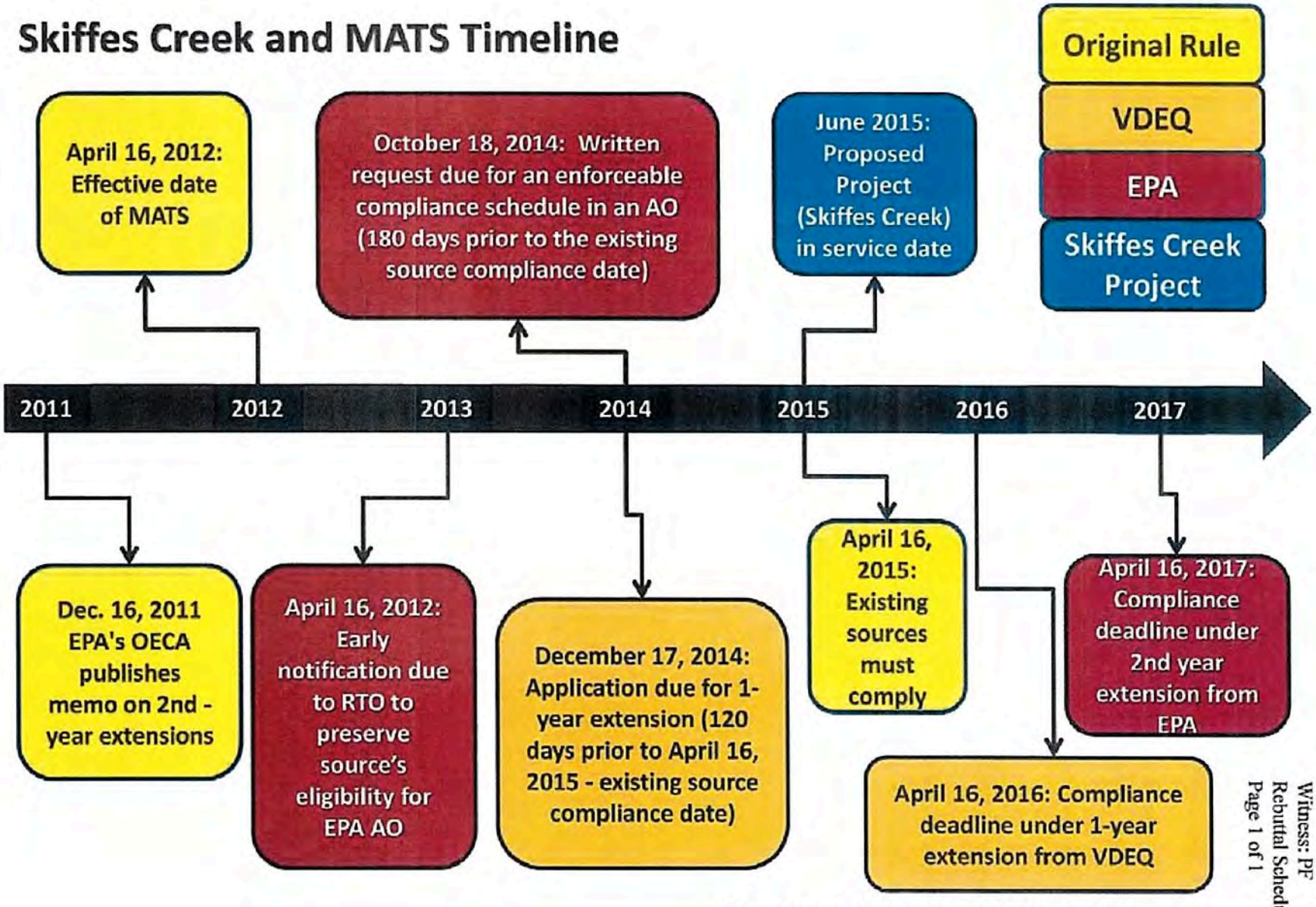
As a transmission owner and operator, Dominion Virginia Power is required to plan and operate their power infrastructure in a manner that meets regulatory requirements and provides reliable service to their customers in a cost-effective manner. In addition to evaluating alternatives through Dominion's internal planning, the Integrated Resource Plan, the proposed project has been reviewed by the Regional Transmission Operator PJM as well as the Virginia State Corporation Commission. A brief summary the of these regulating bodies, Dominion' and PJM's planning process and rules governing the proposed project is offered below to provide a context in which to review the proposed project and alternatives considered.

2.1 MERCURY AND AIR TOXICS STANDARDS (MATS) RULE

On December 16, 2011, the Environmental Protection Agency (EPA) promulgated the Mercury and Air Toxics Standards (MATS rule). The purpose of the rule is to reduce the emissions of toxic pollutants from power plants, and specifically from new and existing coal and oil-fired electric utility generating units (EGUs). Compliance timelines were provided in the rule for existing sources. Initial compliance for all sources was required by April 2015 (Figure 2-1. EPA MATS Compliance Timeline). Under the Clean Air Act, state permitting authorities were given the power to grant an additional year extension as needed. Dominion has applied for, and been granted, this extension from the Virginia Department of Environmental Quality (DEQ).

The EPA also provided a pathway for reliability critical units to operate for an additional year through an EPA administrative order. However, the EPA anticipated few, if any, situations where this pathway would be needed. Other situations where compliance cannot be achieved in the given timeframes will be addressed on a case-by-case basis. Utility operators are only eligible to notify the EPA of their intent to apply for an Administrative Order to permit operations during the fifth year within one year *after* the effective date of MATS, as may be extended by the state permitting authority. As such, there is no precedent in place for an additional extension of compliance with the MATS rule. According to the EPA, such an extension would require the use of an enforcement Administrative Order. The MATS rule does not provide any mechanism for operation of non-compliant units beyond April 16, 2017. Continued operation of any non-compliant units after April 16, 2017 would be in direct violations of federal law.

In addition to the MATS rule, other regulations currently in effect do not offer the opportunity for extensions. These include the Cross State Air Pollution Control Rule (CSAPR), which will replace the Clean Air State Interstate Rule (CAIR) beginning in January 2015, the ozone national ambient air quality standards (NAAQS), the sulfur dioxide (SO_2) NAAQS or the §316(b) rule of the Clean Water Act. The proposed project provides for compliance with all current regulations and the MATS rule by April 2016. Any viable alternatives would also require compliance with these laws within the required timeframes.



Note: Per the testimony of Pamela F. Faggert, at this time Dominion believes it does not meet the requirements for seeking these extensions.

Figure 2-1. EPA MATS Compliance Timeline

Company Exhibit No. __
Witness: PF
Rebuttal Schedule 1
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2.2 FERC/NERC

The interstate transmission of electricity, natural gas and oil is regulated by the Federal Energy Regulatory Commission (FERC). Under the Energy Policy Act of 2005, additional responsibilities were delegated to FERC, including protecting the reliability of the high voltage interstate transmission system through the implementation of reliability standards. FERC has designated the North American Reliability Corporation (NERC) as the Electric Reliability Organization for this purpose within the United States. As such, NERC is responsible for the development and enforcement of reliability standards, annual and seasonal assessments of long-term reliability, monitoring the bulk power system and educating, training and certifying industry personnel. It is not within NERC's purview to require the construction of new generation or transmission or adopt enforceable standards that have that effect.

Prior to the Blackout of 2003 which affected an estimated 55 million people in the Northeastern United States and Canada, compliance with reliability standards was voluntary. The enactment of the Energy Policy Act provided mandatory NERC Reliability Standards which constitute minimal criteria with which all public utilities must comply as components of the interstate electric transmission system. Utility operators could be fined up to $1 million a day per violation if found to be in non-compliance.

The standards require that the transmission system be tested for near term reliability (1-5 years) and long term (6-10 years). Identification of conditions where portions of the transmission grid and equipment will exceed operational parameters is performed under varying scenarios including, but not limited to, loss of a single tower, outage of an entire line segment or loss or reduction of generation. These critical conditions fall into four basic categories requiring varying levels of response based on the severity of the condition. The four contingency categories are defined as Categories A, B, C and D. Category D events are the most severe and may having far-reaching effects such as cascading outages. As stated above, the proposed project is required to meet NERC Reliability Standards and avoid violations of these criteria that will occur as a result of the retirement of Yorktown Units 1 and 2 in 2016.

2.3 DOMINION INTEGRATED RESOURCE PLANNING

In accordance with §56-599 of the Code of Virginia and the Virginia State Corporation Commission (SCC) guidelines, Dominion is required to file an Integrated Resource Plan (IRP) every two years with the SCC. The IRP is reviewed by the SCC and, after giving notice and opportunity to be heard, the SCC determines whether the IRP is reasonable and is in the public interest. Dominion developed four alternative plans representing plausible future paths. These plans were evaluated using a variety of scenarios and sensitivities. Ultimately, the selected plan contained the best mix of resources to meet energy efficiency needs in a reliable, cost-effective manner. Dominion filed its preferred 2011 IRP to the Virginia SCC on September 1, 2011. The plan includes load forecasting, existing and proposed resources, planning requirements, constraints and future resources in both a near-term plan (2012-2016) as well as a long-term action plan (2017-2026).

The plan evaluated the use of supply-side resources which include existing generation, transmission and renewable energy resources. Demand-side management (DSM) resources, or activities and programs undertaken to influence the amount and timing of electricity use, and market purchases from outside power generators were also evaluated. As part of the planning process, Dominion analyzed the potential retirement of several coal- and oil-fired generation units that were at risk of being non-compliant with the expected EPA MATS rule effective 2015. Three options were analyzed for each at risk unit: (1) retrofitting with additional environmental control reduction equipment; (2) fuel repowering to biomass or natural gas; or (3) retiring the unit. These options are addressed in further detail below for the Yorktown Units in Section 3.2.1.

As a result of the planning process, Dominion filed notice with PJM on November 7, 2011 of their intent to retire Yorktown Power Station Unit 1 by December 31, 2014 (now 2015). Power flow studies of the effects of this retirement show the projected in-service date of the proposed Project must be accelerated from the summer of 2019 to the summer of 2015 (now 2016 with the granting of the DEQ extension) to maintain compliance with NERC reliability standards. The retirement of Yorktown Unit 2 was identified in the 2012 IRP further driving the need for the project.

2.4 PJM REGIONAL TRANSMISSION OPERATOR

Dominion is part of the PJM Regional Transmission Operator (RTO) territory which provides service to a large portion of the eastern United States. PJM is responsible for ensuring the reliability and coordinating the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Dominion's load zone is the third largest in the PJM territory serving approximately 2.4 million customers. Dominion also serves several retail customers including Appalachian Power Company (APCO), Old Dominion Electric Cooperative (ODEC), Northern Virginia Electric Cooperative (NOVEC), Central Virginia Electric Cooperative (CVEC), Virginia Municipal Electric Association (VMEA), North Carolina Electric Membership Corporation (NCEMC) and North Carolina Eastern Municipal Power Agency (NCEMPA).

PJM undertakes a regional transmission expansion planning (RTEP) process on an annual basis to assess system reliability issues. Dominion Virginia Power, along with other Transmission Owners in PJM, is actively involved in the development of reliability and power flow models used in the RTEP process. The active participation of Transmission Owners in the development and assessment phases of the process is critical to ensure a comprehensive and accurate plan. Viable solutions are identified on a regional and sub-regional scale. The process includes a review of transmission plans developed in previous years to determine if proposed transmission upgrades are still needed and/or if changes of in-service dates are required. While PJM's role is to ensure the reliability of the bulk power system, they also consider non-transmission alternatives such as DSM as well as the addition and deactivation of generation within the system which ultimately affects the amount of power available.

PJM performed sensitivity analyses to evaluate the performance of transmission projects should Yorktown Units 1 and 2 retire. Their analysis also included DSM-response and alternative transmission projects proposed by energy developers other than Dominion. Specifically, PJM noted that there is limited availability of DSM to offset the loss of generation and an overall lack of new generation development in the area (Herling Rebuttal Testimony, Public Volume I of VI, p. 7, filed March 14, 2013). A number of transmission alternatives from other transmission developers, including both 500 kV and 230 kV facilities, were also reviewed by PJM as part of their planning process. PJM ultimately found Dominion's proposed Project to be the most effective solution to resolve the identified NERC violations within the required timeframe.

As stated in the Rebuttal Testimony of Mr. Steve Herling, Vice President of Planning for PJM Interconnection, LLC:

> "The analysis performed by PJM, (Dominion), and the Commission staff have all demonstrated the ineffectiveness of 230 kV transmission solutions. Based on the limited availability of DSM, the lack of new generation development, and the potential for future generation retirement in the area, it is critical that a strong new 500 kV source be introduced to support the long-term reliability of service to customers in the area" (Herling Rebuttal Testimony, Public Volume I of VI, p. 22, filed March 14, 2013).

2.5 VIRGINIA STATE CORPORATION COMMISSION

The Virginia State Corporation Commission (SCC) is responsible for determining the need, route and environmental impact of transmission lines at or above 138 kV within Virginia. The SCC's Division of Energy is tasked with supporting the SCC in ensuring that Virginia consumers receive adequate utility services at just and reasonable rates. The attached flowchart outlines the SCC process. Dates specific to the Surry – Skiffes Creek – Whealton project are included for reference (Figure 2-2. SCC Transmission Line Approval Process).

The SCC regulatory proceeding began when Dominion filed its Application for Approval and Certification on June 11, 2012. The process included multiple opportunities for public participation and comment, as well as the opportunity to formally enter into the legal case as a Respondent. Thirteen parties participated in the SCC proceeding, including Charles City County, James City County, BASF, Save the James Alliance, James River Association, Old Dominion Electric Cooperative (ODEC) and landowners both collectively and individually.

During the SCC review process, the SCC staff retained two independent experts to evaluate Dominion's application to the SCC. One consultant, Mr. John W. Chiles, Principal – GDS Associates, Inc., was hired to provide an independent analysis of the need for the project as well as develop alternatives for the project. A second consultant, Mr. Wayne D. McCoy, President – Mid Atlantic Environmental LLC, was hired to conduct an independent routing and environmental assessment of the project. Mr. Chiles' analysis verified Dominion's power flow results and concluded that the project adequately addresses the identified reliability needs. Mr. Chiles also agreed with Dominion and PJM that none of the 230 kV alternatives (single or

The Transmission Line Approval Process - - Surry-Skiffes Creek-Whealton

Virginia's State Corporation Commission (SCC) has regulatory authority over all electric utilities and requires that all transmission facilities at or above 138 kV be certified by the SCC.

The SCC determines the need for a proposed line and the route. Among other elements considered, the SCC must determine that the selected route reasonably minimizes the impact on scenic assets, historic districts, and the environment.

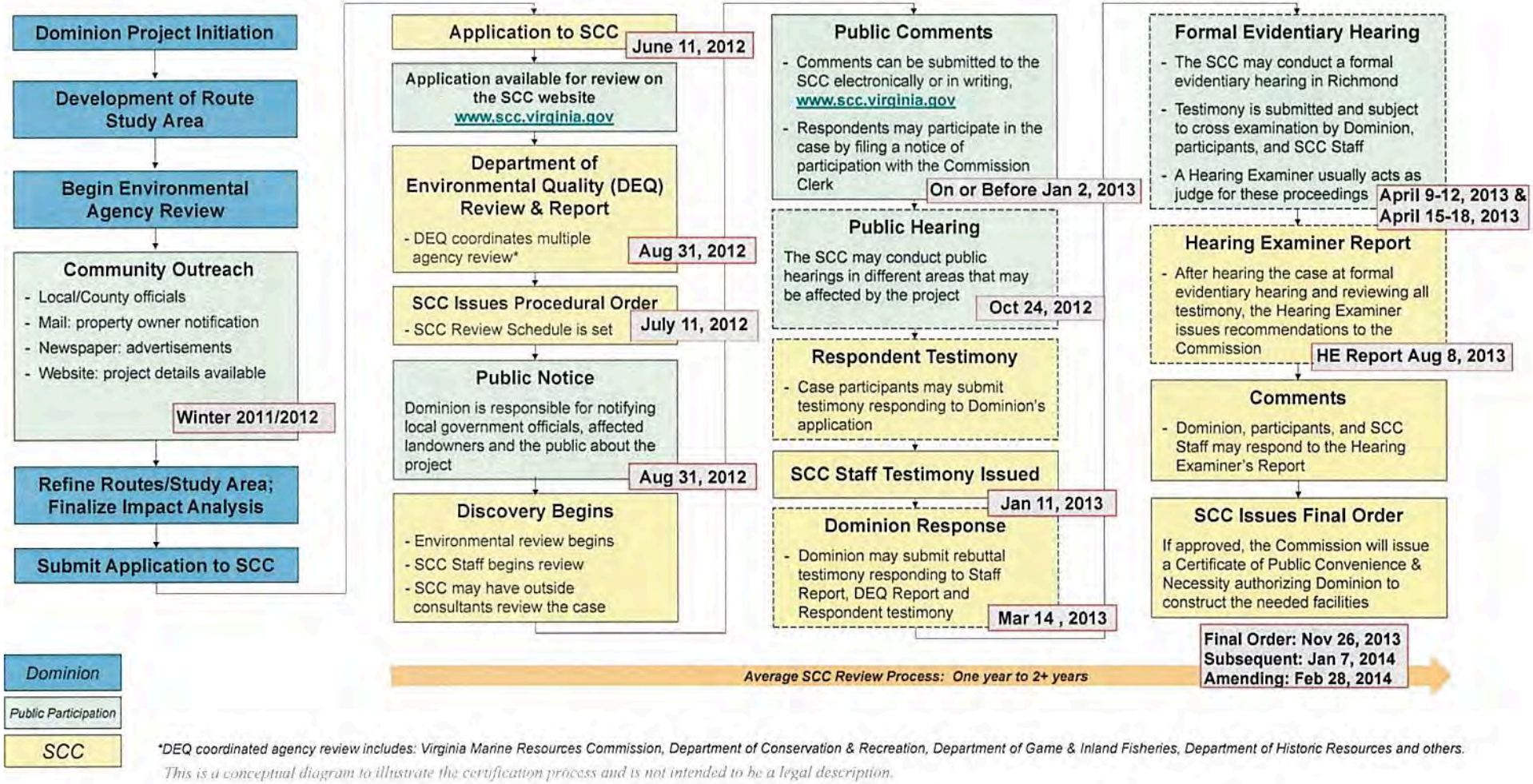

Figure 2-2. SCC Transmission Approval Process

double circuit, overhead or underground) are viable in terms of meeting the identified reliability need. Similarly, Mr. McCoy concluded in his review that while the proposed project is subject to unique characteristics which make routing of the project particularly challenging, the proposed project is the best alternative to address the reliability issues within the NHRLA. The testimonies of Chiles and McCoy are contained in the Prefiled Staff Testimony, Volumes 1 and 2, respectively filed to the SCC on January 11, 2013. This sentiment concerning the Project was echoed within the August 2, 2013 Report of the Hearing Examiner and also by the SCC's November 26, 2013 Final Order, pages 15-16, wherein the SCC stated, "the crossing of the James River in this area is reasonable", and found that "based upon the extensive factual record in this case, the construction of the Proposed Project, as approved herein, will reasonably minimize adverse impacts on the scenic assets, historic districts, and environment of the area concerned."

Within the case proceedings of the Project, the SCC also directed Dominion to present evidence regarding the feasibility, cost and advisability of additional alternatives. Dominion conducted the required analysis to respond to this request and provided information regarding underground 230 kV alternatives, rebuilding of 230 kV lines within the region, a combination of 230 kV transmission and retention of, or new generation, at Yorktown Power Station and stand-alone generation options at Yorktown. The specifics of these alternatives are discussed further in subsequent sections of this response. The results of the additional studies showed that the proposed project was the only viable option to meet reliability, schedule and cost constraints.

3.0 Alternatives Analysis

As detailed above, Dominion has undertaken an extensive planning effort to identify the project that is the least environmentally damaging practicable alternative that meets the purpose and need of maintaining NERC compliance upon the retirement of Yorktown Units 1 and 2. The planning process is reviewed and independently verified by PJM, the Regional Transmission Operator. PJM has concurred with Dominion's assessment that a 500 kV line is required to offset the loss of generation to the NHRLA. Additionally, as part of the SCC hearing, independent consultants reviewed and supported Dominion's conclusions regarding the electrical need, scheduling constraints and environmental compliance challenges resulting in the required construction of the proposed project. The subsequent sections provide further detail as to the alternatives considered throughout the planning process. These include 230 kV options, both overhead and underground, combination transmission and generation alternatives, retrofitting and repowering generation alternatives and the no build alternative. Additional discussion is provided regarding the feasibility of the construction of alternative 500 kV lines in alternative corridors, as well as an underground 500 kV line. The potential to construct an underground High Voltage Direct Current (HVDC) line under the James River is also discussed.

3.1 NO ACTION ALTERNATIVE

Under the No Action alternative, Dominion will be required to retire Yorktown Units 1 and 2 by April 2016 to comply with the EPA MATS rule. The loss of electrical service through a broad swath of the Commonwealth of Virginia during high demand days will occur at this time unless the electric transmission system is reinforced. Dozens of engineering studies were performed by Dominion, PJM, GDS and James City County Witness Mr. Whittier. In addition, GDS, as directed by the Staff of the SCC, conducted independent studies and also verified all of the Dominion Studies. In all cases, several cascading outage scenarios affecting areas from the NHRLA into northern Virginia, City of Richmond and North Carolina were identified. Absent system improvements by the implementation date of the EPA's MATS Rule the quality of life and economic vitality of the region could be crippled. The Hearing Examiner's Report (August 2, 2013 page 134) reads:

> "No respondent challenged the results of the Company's (Dominion's) load flow studies or the effectiveness of the Proposed Project to resolve identified NERC Reliability Violations."

Additional information regarding the existing transmission and generation infrastructure in the region is provided below, as well as the determined effects if the purpose and need of the project is not met.

3.1.1 Existing Conditions

The existing NHRLA includes 14 counties and seven cities largely located along the peninsula area of southeastern Virginia. Specifically, the NHRLA includes the counties of Charles City, James City, York, Essex, King William, King and Queen, Middlesex, Mathews, Gloucester, King George, Westmoreland, Northumberland, Richmond and Lancaster and the Cities of Williamsburg, Yorktown, Newport News, Poquoson, Hampton, West Point and Colonial Beach. This area consists of 589,463 citizens of the Commonwealth of Virginia or conversely approximately 280,000 of Dominion's 2,500,000 customers. The NHRLA is generation deficient, meaning that the region is unable to produce all its power needs and must rather import a portion of its power requirement from external generation sources. The remaining power requirement is provided by the Yorktown Power Station. The power station currently has a generating capacity of approximately 1141 MW derived from two coal-fired generating units and one heavy oil-fired generating unit. Further details regarding the generation capabilities within the NHRLA and surrounding region is provided below as well as a discussion of the known consequences of the retirement of Yorktown Units 1 and 2 under the No Action alternative.

3.1.2 Yorktown Units 1 and 2 Retirement

The Yorktown Power Station consists of two coal-fired generating units and one oil-fired generating unit. This power station currently has a generating capability of approximately 1,141 MW. Units 1 and 2 were built in 1957 and 1959, respectively, and consume more than 2,200

tons of coal a day when in operation. Due to the age of these units and prohibitive costs to maintain compliance with regulations, Dominion determined in their 2011 and 2012 IRPs that these units would be retired. The SCC agreed with Dominion's analysis (Case No. PUE-2012-00029) that the environmental risks associated with continued capital investment to maintain compliance with federal regulations, at a net present value to Virginia customers of more than $1 billion, was not in the best interest of customers. With the retirement of Units 1 and 2, Dominion's short term planning criteria have identified violations of NERC Category B, C and D standards under the No Action alternative due to the retirement of Yorktown Units 1 and 2. Several system conditions were identified based on current and projected load growth from 2012 – 2017, which Dominion is required to account for. Additional violations above and beyond these were identified in conjunction with the loss of Yorktown Units 1 and 2 by summer of 2016, thus driving the need for the project.

3.1.3 Load Shed Requirements on High Demand Days

Absent an improvement to the load area upon implementation of the EPA MATS Rule and the retirement of Yorktown Units 1 and 2, Dominion will be required to implement pre-contingency load shedding (i.e., rolling blackouts) in the NHRLA to prevent the possibility of cascading outages impacting the reliability of the interconnected transmission system. Based on current load profiles, it is estimated that rolling blackouts would initially occur 80 days a year and would continue to increase in number as load continues to grow in the area. Based only on system loads (i.e., not accounting for other contingencies or unforeseen outages that may occur), the majority of these load shed days would occur in the peak electric months of June, July, August, September, December and January. The amount of load to be shed on a pre-contingency basis is estimated to between 220 MW and 240 MW or approximately 20 - 25% of the total number of customers in this load area. Should planned or unplanned outages occur during different times of the year, then additional days that require planned blackouts may increase. Should one of the identified critical contingencies actually occur, it will be necessary to load shed an additional 30% of customers demand. Therefore, the potential exists that up to 50% of the customers in this load area could be without electricity for days or even weeks until the event which caused the failure could be fixed.

3.1.4 Economic Impacts

The NHRLA has a diverse mix of customers from government defense facilities, industrial sites, commercial sites and residential end users. Major facilities which would be impacted by local load shedding would include Joint Base Langley-Eustis, Yorktown Naval Weapons Station, NASA, Newport News Ship Building, Cannon, Anheuser-Busch Brewery, Thomas Jefferson National Accelerator Facility, College of William and Mary, Christopher Newport University, Busch Gardens, Water Country USA, Distribution Centers (like Wal-Mart, Food Lion) and the Historic Jamestown-Colonial Williamsburg Complex. Critical services such as 911 call centers, fire and emergency response centers, water and sewer treatment facilities and hospitals located in the NHRLA localities would also be impacted by the required blackouts.

Rotating outages impacting 20 - 25% of the customers at any one time will impact every customer in the area to one degree or another. For most customers in the NHRLA, they will experience outages of electrical service for two hour blocks on a rotating basis (sometimes referred to as rolling blackouts). The implementation of rolling blackouts requires that the next phase of a load shedding begin prior to restoration of service of the current phase of customers who do not have electrical service. Therefore, at any one time it is quite possible that 35-40% of the customers in the NHRLA will not have electrical service do to the requirements of needing to keep the system in a stable operating mode.

3.1.5 No Action Alternative Consequences

The SCC stated on page 12 of its November 26, 2013 Final Order that the reliability risks in this case are far reaching and significant.

> "Studies evaluating further stresses to Dominion's transmission system reveal cascading outages spreading from the North Hampton Roads Area into northern Virginia, the City of Richmond, and North Carolina absent alleviation. Dozens of engineering studies in this case, which have been independently verified by our Staff, demonstrate that significant reliability risks exist as early as 2015."

The dependency of modern society on available, reliable electrical service was clearly demonstrated during the Northeast blackout of 2003. This widespread event resulted in power outages throughout the northeastern and Midwestern portions of the United States and parts of Canada. The blackout lasted for up to two days in some locations, and affected more than 50 million people. More than 580 generating units shut down and 80% of the power load to the affected area was lost. The economic impact of the blackout was estimated at $6 billion dollars. In addition to economic and financial impacts, potential life threatening situations occurred when local governments were no longer able to provide basic functions such as potable water, sewer and emergency response. Telephone circuits remained operational but were overloaded as cellular service was interrupted. Most of the northeast corridor of Amtrak was interrupted as well since it uses electric engines. These are just a few examples of the very clear relationship between reliable power, economic stability and social and national security. As a result of this event, numerous regulations were developed and passed, including the Energy Policy Act of 2005, to establish and regulate electrical compliance with reliability criteria and ensure that a similar situation does not occur. Under the No Action alternative, the residents, business and critical defense installations located within the NHRLA will clearly experience far-reaching economic and social impacts but for an indefinite amount of time.

The potential for the residents of the Commonwealth of Virginia who live in the NHRLA let alone the business and critical national defense facilities which are located in this region to experience substandard electric service was rejected by the SCC as stated on page 22 of the November 26, 2013 Final Order:

> "James City County, Save the James, and James River Alliance 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. 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. 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 Yorktown Power Station, which is subject to environmental restrictions that will severely limit its operation until its retirement. 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, establishes a clear need for significant new electric infrastructure to address fast-approaching reliability violations projected for Dominion's transmission system."

To deliberately plan to operate a transmission system in a manner where it is no longer capable of meeting a society's basic requirements is completely unacceptable and unallowable under federal regulations. Based on the extreme and far-reaching social and economic effects associated with the No Action alternative, the purpose and need of the project is clearly demonstrated.

3.2 OFFSITE ALTERNATIVES

Dominion conducted an extensive alternatives analysis in conjunction with their state-mandated IRP process, federally mandated PJM RTEP process and the state mandated Certificate of Public Convenience and Necessity (CPCN) at the SCC. These alternatives were presented as part of the SCC hearing, and extensive testimony was presented detailing the reasons why the proposed project is the preferred alternative. The proposed project was ultimately supported by PJM, the SCC and verified by independent reviewers leading the SCC to issue a final order of approval. Below is a summary of the major offsite alternatives considered. Additional information can be found in the attached SCC rebuttal testimonies of Hathaway, Nedwick, and Kelly (Public Volume I of VI, filed March 14, 2013).

3.2.1 Generation Alternatives

Three options exist for aging coal- and oil-fired generation units to obtain compliance with the EPA MATS rule: (1) retrofit existing units to achieve required emission reductions; (2) repower existing units with alternative fuel sources to achieve required emission reductions; or (3) retire the unit. A number of factors drive the decision as to the appropriate course of action, and Dominion thoroughly examined all possible options for meeting compliance with the regulations.

3.2.1.1 Retrofitting Yorktown Units 1 and 2

Dominion evaluated the steps required to retrofit Yorktown Units 1 and 2 and bring them into compliance with the EPA MATS rule. Yorktown Units 1 and 2 were built in 1957 and 1958

respectively, and consume more than 2,200 tons of coal a day when in operation. Upon implementation of the EPA MATS Rule, these units will be nearly 60 years old and would require capital-intensive environmental equipment upgrades and additions to maintain compliance with current and proposed EPA regulations. Retrofitting the Yorktown units would only temporarily delay the need for transmission upgrades within the region to 2019 but at a cost of over $1 billion to the Virginia customer. Moreover, the retrofitted facilities would still be less efficient than newer generation facilities and burn more fuel to achieve the required capacities.

The SCC determined as part of its review of the proposed project that the environmental risks associated with efforts to maintain compliance with current and future federal regulations and the associated costs was not a reasonable alternative for ensuring transmission reliability to the NHRLA. Due to the extreme costs and temporary nature of the solution, this alternative does not meet the project purpose and need of providing cost-effective, reliable power to the NHRLA region.

Dominion has also considered retrofitting Yorktown Unit 3. This unit is expected to be limited to an 8% of capacity factor beginning in 2015 to comply with the EPA MATS rule. Similar to the other units, the cost to retrofit this unit was found to be extensive and was not considered to be an effective solution. In addition to the cost, Unit 3 would be difficult to operate as a reliability unit as it is not capable of quickly cycling to meet local reliability constraints. Last, Yorktown Unit 3 is one of the most expensive units in Dominion's fleet to operate. It is typically only used under heavy loads. Operating this unit on a regular basis will have a significant impact on customer fuel costs – approximately $2.5M per day versus market purchases. Retrofitting the Yorktown Units is not cost-effective and does not meet the purpose and need of the project.

3.2.1.2 Repowering Yorktown

Dominion examined the potential to repower some or all of the Yorktown units to natural gas in light of the extensive costs to retrofit these facilities. From a capital perspective, this was a more favorable option than retrofitting existing units. A scenario was examined in which Yorktown Unit 1 was retired and Yorktown Unit 2 was converted to gas and oil. Even under this scenario, the proposed Surry – Skiffes Creek – Whealton project is required to be constructed by 2016 to meet NERC reliability criteria. Additionally, there is currently no sufficient gas supply to support year-round operation of gas-fired generation at Yorktown and significant expansion of the regional gas supply would be required (Kelly Rebuttal Testimony, Public Volume I of VI, filed March 14, 2013). Through the 2011 IRP and in context of an alternative to the Project, Dominion explored the feasibility of supplying Yorktown and other generating sites with natural gas for fueling. In addition to significant costs, the construction of the necessary infrastructure to accommodate gas capacity to fuel Yorktown would not be able to be completed within the required timeframe. More recent information confirms that adequate fuel supply would not be available before 2018, at the earliest. As such, this alternative was not considered further as it does not meet the project purpose and need of resolving NERC reliability criteria violations on time.

Table 3-1. Additional Analyses Summary Results

	A	B	C	D	E	F	G	H	I
			Alternative A[1] - 230kV		Alternative B[2] - 230kV		Alternative C[3] - 230kV		
	Proposed Project Including 500 kV Updated Proposed Route	Overhead 500 kV Chickahominy Alternative	Transmission Only	Transmission Plus *Generation*[9]	Transmission Only	Transmission Plus *Generation*[9]	Transmission Only	Transmission Plus *Generation*[9]	Stand Alone *Generation* Option[4,9]
1 Does project electrically address 2015 NERC Reliability Violations?	YES	YES	NO	YES[5]	NO	YES[5]	NO	YES[5]	YES[5]
2 COST	$155.4 M	$213.2 M	$273.8 M	$623.8 M	$440.4 M	$540.4 M	$144.8 M	$494.8 M	$633.0 M
3 If "NO" in Line 1, what is the cost of additional transmission facilities to fully resolve 2015 NERC Reliability Violations?	Ø	Ø	$214.8 M	Ø	$48.2 M	Ø	$ 82.1 M	Ø	Ø
4 Total COST to fully resolve 2015 NERC Reliability Violations	$155.4 M	$213.2 M	$488.6 M	$623.8 M	$488.6 M	$540.4 M	$ 226.9 M	$494.8 M	$633.0 M
5 Can construction necessary to fully resolve 2015 NERC Reliability Violations be completed by June 1, 2015?[6]	YES	YES**	NO	NO	NO	NO	NO	NO	NO
6 Can construction necessary to fully resolve 2015 NERC Reliability Violations be completed by April 16, 2017?[7]	YES	YES **	NO	YES**	NO	NO	NO[8]	NO	YES**
7 Additional COST to fully resolve 2021 NERC Reliability Violations	$17.3 M	$17.3 M	$26.7 M	$577.0 M	$26.7 M	$577.0 M	$181.9 M	$577.0 M	$712.0 M
8 Total COST to fully resolve 2021 NERC Reliability Violations	**$172.7 M**	**$230.5 M**	**$515.3 M**	**$1,200.8 M**	**$515.3 M**	**$1,117.4 M**	**$ 408.8 M**	**$1071.8 M**	**$1,345.0 M**
9 Completion date for facilities to address 2015 NERC Reliability Violations	2015	2015	2018	2017	2018	2018	N/A[8]	2021	2016

Notes:

1 Alt. A: underground 230 kV hybrid single circuit (1000 MVA) on James River Crossing Variation 3 Hybrid Conceptual Route.
2 Alt. B: underground 230 kV hybrid double circuit (1000 MVA/circuit) on James River Crossing Variation 3 Hybrid Conceptual Route.
3 Alt. C: rebuild of the existing James River crossing of 230 kV Line #214 and 230 kV Line #263.
4 Amount of generation at Yorktown that is the "lowest" cost to solve the need. 620 MW in 2015 and 2021 (2 units minimum; lose 1 unit and maintain ≥ 295 MW).
5 Electrically resolves NERC Reliability Violations assuming generation at Yorktown is retained and/or added until violations are resolved.
6 Date by which the 2015 NERC Reliability Violations must be resolved.
7 If requested and granted, date by which fourth and fifth year MATS extensions end.
8 Alternative C is NOT constructible without generation already in place to address reliability issues that result from the wreck and rebuild of existing lines.
- Generation required to be in place to support construction would cost between $383M - $652M.
- To construct the facilities needed to address NERC Reliability Violations in 2015 would take 10 years. Additional construction time would be needed to address 2021 NERC Reliability Violations.
9 Retrofit and repower options require 3-years of capital expenditures for construction and implementation (excluding permitting), beginning July 1, 2013. Effect of multiple retrofit and repower options being executed at the same time has not been incorporated.

**The information presented in the table above was prepared for consideration during the SCC proceedings and does not reflect the one-year extension to the MATS rule recently granted by the DEQ. As of the preparation of this Alternatives Analysis, only the proposed Project, the Surry-Skiffes Creek-Whealton Line, can be constructed in time to meet the April 16, 2016 NERC compliance date.

3.2.1.3 Combination Generation Alternatives

Several combinations of retrofitting, repowering and retirement combined with transmission construction were also evaluated. These included several configurations of 230 kV lines, both overhead and underground, combined with retention of generation at Yorktown. The lowest cost alternative would be over three times the cost of the proposed project to address the 2016 NERC compliance and over six times the cost to solve additional 2021 violations (Table 3-1). In addition, none of these combination alternatives can resolve all NERC Reliability Violations in 2016 without the construction of additional transmission or generation (Nedwick Rebuttal Testimony, Public Volume I of VI, filed March 14, 2013).

These projects are neither cost-effective nor can they be completed in the required timeframe to meet the purpose and need of the project for the 2016 compliance date. The proposed project resolves all 2016 reliability issues and requires only a minor upgrade of a 115 kV line in the area to continue to resolve NERC Reliability Violations in 2021. As such, generation combination alternatives are not practicable and were not considered further.

3.2.1.4 New Generation

Upon the determination that Yorktown Units 1 and 2 should be retired, Dominion considered new generation options throughout the area. Options such as combined-cycle, combustion turbine and coal generation were considered. In addition, new gas-fired generation in the region is challenged by the same gas supply limitations that make repowering Yorktown 1 and 2 not cost-effective and unable to be completed by 2016. New coal units would face compatibility challenges with proposed EPA regulations making their long-term viability questionable. Small scale generation sources such as biomass, wind and solar were also considered but not sited within this region based on their relative cost or suitability to the region. For example, wind generation would require substantial transmission infrastructure upgrades totaling approximately $1 – 2 billion according to a 2012 North Carolina Transmission Planning Cooperative (NCTPC) – PJM Joint Interregional Reliability Study.

Stand-alone generation is also constrained by schedule and cost. The lowest cost of a stand-alone generation solution was found to be $633 million to satisfy 2016 NERC reliability criteria compared to the estimated $154 million of the proposed project. An additional $722 million would be required to provide sufficient generation by 2021, bringing the total cost of a stand-alone generation solution to an estimated $1.3 billion. By contrast, an additional $17.3 million would be required for the proposed Surry – Skiffes Creek – Whealton project to meet 2021 reliability criteria (Table 3-1). Stand-alone generation would also face significant siting, permitting and construction timeline constraints in order to be in service by 2016. As such, the construction of new generation does not meet the purpose and need and is not a practicable alternative for providing cost-effective power within the required timeframe to meet NERC reliability criteria in 2016.

3.2.2 Demand-Side Management

Other Project alternatives examined included Demand-Side Management, or DSM. Rather than approaching power usage from the supply side, DSM resources include activities and programs undertaken to influence the amount and timing of electricity use, as well as market purchases from outside power generators to reduce overall demand. DSM resources are already included in the transmission planning process by both Dominion and PJM. Additional amounts cannot be assumed to be available to address NERC reliability violations due to transient and voluntary nature of these resources. There are practical problems with relying on DSM to solve reliability violation as they are not effective in an instantaneous event (Herling Rebuttal Testimony, Public Volume I of VI, filed March 14, 2013). DSM resources are insufficient and not a practicable alternative to alleviate NERC reliability criteria violations and do not meet the purpose and need of the project.

3.2.3 Alternative Corridors

The implementation of the EPA MATS rule will result in the transmission system in the NHRLA no longer being compliant with federally mandated NERC reliability criteria. No party, whether it would be Dominion, the SCC or any intervener in the case before the SCC, disputes that fact. During the course of the case before the SCC, over eighteen different potential solutions were evaluated as to their effectiveness in resolving the identified NERC criteria violation by the implementation date of the MATS rule. Key alternatives analyzed include the:

- Line 214/263 230 kV Line Rebuild (James River Bridge Crossing);
- Chuckatuck – Newport News 230 kV Line (Whittier Hybrid);
- Surry – Whealton 500 kV Line;
- Chickahominy – Lanexa 500 kV Line;
- Chickahominy – Skiffes Creek 500 kV Line; and
- Chickahominy – Skiffes Creek 230 kV Double Circuit Line.

Of the alternatives considered, only the Chickahominy – Skiffes Creek 500 kV project is able to resolve NERC violations in the short term. Based on the power load flow models which were independently verified and were uncontested, it was determined that none of the 230 kV transmission alternatives, by themselves, satisfy the NERC reliability requirements for 2016 (SCC Hearing Examiner's Report, page 145, filed November 16, 2013). Each of the five alternatives listed above is described in further detail in the following sections. The alternatives are also compared in Table 3-1.

3.2.3.1 Line 214/263 230 kV Line Rebuild (James River Bridge Crossing)

The NHRLA is currently connected to the Southampton Roads Load Area through two 230 kV overhead lines, Line 214 and Line 263, located adjacent to the James River Bridge. Dominion evaluated rebuilding these lines to a higher capacity. However, the load flow analysis showed that the rebuild of these lines would not resolve the 2016 NERC criteria nor would it resolve the

2021 criteria. This is due largely to the existing generation deficiency present in the Southampton Roads Load Area. The Southampton Roads Load Area is required to import 50-75% of its existing power requirements into the load area from generation resources to the west of Richmond. Therefore, this load area is not in a position to support the transfer of excess power into NHRLA under normal and contingency conditions since no excess power exists. In fact, the proponent of this alternative, James City County witness Whittier, later abandoned this alternative as being viable after modeling studies indicated that it would not work electrically.

Resolution of the 2016 NERC criteria violations would require the investment of $264 million for additional transmission projects and an estimated $383 to $652 million more in generation-related construction to resolve all NERC reliability violations. When combined with the initial project cost of $144 million, this brings the potential total cost of this alternative in excess of $1 billion (Table 3-1). The estimated construction time to complete these projects is after 2020, well after the implementation date of the MATS rule. This alternative is also problematic in that outages of the existing Lines 214 and 263 would be required during the wreck and rebuild of this corridor. Without replacement generation already in place, outages of these lines would also result in NERC violations.

Since this work could not be completed prior to the implementation of the MATS rule, this alternative would result in multiple years of rotating outages in the NHRLA. Due to the significant cost, electrical violations likely to occur and inability to construct the transmission plus generation alternative within the required timeframe, this alternative does not meet the purpose and need.

3.2.3.2 Chuckatuck – Newport News 230 kV Line (Whittier Hybrid)

The Chuckatuck – Newport News 230 kV Line, or the Whittier Hybrid, was presented during the SCC hearing by Mr. Whittier, a witness on behalf of James City County. It involves the building of a new 15.4 mile long transmission line along new or expanded ROW between the Chuckatuck and Whealton Substations. This alternative requires the construction of new line through several miles of wetlands between Chuckatuck and the James River as well as the expansion of existing ROW in congested residential areas. This alternative also involved a new crossing of the James River in the vicinity of the existing James River Crossing. A preliminary routing review for this alternative identified several constraints including: (i) expansion of the existing ROW 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 (Huntington Park, Virginia War Memorial Museum), and thus not subject to eminent domain; and (v) the siting of two underground terminals; (vi) beginning the process for approval of a new transmission line, including open houses, state agency reviews and a new application to the SCC.

Regardless of the physical and routing constraints of this alternative, it was found that this proposed alternative does not resolve all of the NERC reliability criteria. The Hearing Examiner's Report (August 2, 2013 page 148) reads:

> "Mr. Whittier acknowledged that his proposed variations failed to resolve all NERC reliability violations".

Specific to one alternative offered by Whittier, the Hearing Examiner's Report goes on to read that "an initial look still showed us...more violations...than we wanted to see."

To address some of these violations, Mr. Whittier recommended the addition of another 500 kV to 230 kV transformer at Surry, but still admitted that such an addition only "solves almost everything. Not everything." The Hearing Examiner's Report characterizes the Whittier Hybrid as a piecemeal approach (page 151), with fallacies including 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." Consequently, under a piecemeal approach, it is possible that after building one or both of Mr. Whittier's Variations, PJM could again direct Dominion to undertake a project similar to the Proposed Project or the Proposed Alternative Project".

As the project does not meet the electrical requirements, this alternative does not meet the project purpose and need and was not considered further.

3.2.3.3 Surry – Whealton 500 kV Line

The existing Line 214 corridor extends from the Whealton Substation in Hampton to the Surry Power Station in Surry County. As described above, the line crosses the James River adjacent to the James River Bridge. This alternative would entail the construction of a new 500 kV line from Surry to Whealton. Dominion initially evaluated this alternative, but due to numerous physical, electrical, routing and siting and environmental constraints, it was not considered a viable alternative.

One of the most significant issues presented by this alternative is the elimination of the ability to construct an additional 500 kV line from Surry at any point in the future. The configuration of the Surry Power Plant currently allows for the addition of two more 500 kV line getaways. The proposed Surry – Skiffes Creek crossing utilizes one route leaving the other option available for future needs. Construction of a 500 kV line from Surry – Whealton would physically block the ability to construct an additional 500 kV line from this site in the future. The elimination of this option severely impacts Dominion's ability to respond to future growth and reliability issues in a cost-effective manner, and undermines the operational capacity of the Surry Nuclear Power Plant. As described in Section 3.2.1, construction of new generation requires an enormous investment of capital and time. To eliminate the option for an additional 500 kV line in the future is irresponsible and is not a practicable alternative.

Additional challenges remain with a Surry – Whealton 500 kV alternative. The existing corridor housing the 230 kV line is not sufficient to accommodate a 500 kV line and would need to be expanded. This would require acquisition of new ROW through residential areas, historic

districts and large expanses of wetlands. An additional crossing of the James River would be required to be constructed as well. The same obstacles outlined for the Whittier Hybrid in Section 3.2.3.2 would apply here as well. It is unlikely that new ROW could be obtained through Huntington Park (a public beach and recreation area) or the Virginia War Memorial Museum located on the northern shore of the James River. Dominion does not have eminent domain over these areas.

Construction of a new switching station would still be required in conjunction with the construction of a 500 kV line. The likely location for this station would be either the Winchester or Whealton Substation. Either site would need to be expanded by 15 acres or more to accommodate the electrical equipment required to convert the 500 kV line down to the 230 kv connection. Both substations are located in developed, congested areas and would require the demolition of homes and businesses to obtain the necessary expansion area.

Due to these severe constraints, Dominion did not analyze this option further for cost. However, given the extent of new ROW and property required, length of the overall line, and significant impacts to Surry Power Station, this alternative does not meet the project purpose and need and is not a viable option.

3.2.3.4 Chickahominy – Lanexa 500 kV

The existing Lanexa corridor extends from the Chickahominy Substation in Charles City County to the Lightfoot Substation in Lightfoot, Virginia. This alternative evaluated the potential to expand a 14.3 mile section of this existing corridor to construct a new overhead 500 kV line.

The Lanexa corridor is currently occupied by three 230 kV lines and one 115 kV line. These transmission lines are the sources of bulk power into the NHRLA from the Richmond area. While this alternative allowed for the construction of a 500 kV line instead of a 230 kV line, it was ultimately dismissed as it did not resolve the potential for cascading outages. Specifically, the alternative required the installation of an additional line within an existing ROW. Any event causing the loss of the ROW would result in cascading outages impacting the NHRLA, northern Virginia, the City of Richmond and parts of North Carolina. This is the fundamental electrical difference between building a new transmission line from the Chickahominy substation to the NHRLA within an unused ROW (the Chickahominy – Skiffes Creek 500 kV Line alternative, see Section 3.2.3.4) and constructing a line within the existing Lanexa corridor. As this alternative is not electrically viable and does not resolve NERC reliability criteria violations, it does not meet the project purpose and need and was not considered further.

3.2.3.5 Chickahominy – Skiffes Creek 500 kV

The Chickahominy – Skiffes Creek alternative utilizes an existing ROW owned by Dominion that extends approximately 37.9 miles from the Chickahominy Substation in Charles City County to the proposed Skiffes Creek Switching Station in James City County. Approximately 13 miles of this route is existing, cleared ROW while the remaining 24.9 miles is unimproved ROW that

would require clearing for construction of the proposed line. The details of this alternative were presented in the JPA and are described in additional detail here.

Two potential options were evaluated for the Chickahominy – Skiffes Creek route - the construction of a 500 kV line and the construction of a double circuit 230 kV overhead line. As detailed earlier in this document, it was determined through power flow studies that a 500 kV solution was needed. Even with the double circuit 230 kV alternative, additional projects would be needed to maintain long-term reliability. As the overall impacts from construction would be the same for either a 500 kV line or a double circuit 230 kV line and the 230 kV line would not resolve the NERC violations, the double circuit 230 kV line is not a practicable alternative.

The Chickahominy – Skiffes Creek 500 kV line is functionally equivalent electrically to the proposed Surry – Skiffes Creek 500 kV line and resolves the NERC reliability violations due to the retirement of Yorktown Units 1 and 2 by 2016. Environmental and cultural resource field studies were undertaken by Stantec Consulting Services, Inc. (Stantec) on behalf of Dominion to evaluate the use of this corridor. The environmental impacts associated with this route are significantly greater than those for the proposed Surry – Skiffes Creek route. Specifically, the Chickahominy route crosses 93.32 acres of non-tidal wetlands, 8.64 acres of tidal wetlands and requires the clearing and permanent conversion of 62 acres of palustrine forested wetlands (PFO). In contrast, the Surry route crosses only 1.20 acres of tidal wetlands, all of which will be spanned to avoid direct impacts to these systems, and only required the conversion of 0.57 acres of PFO wetlands.

The Chickahominy route crosses the Chickahominy River and would require the construction of at least one tower within the river, as well as the likely placement of additional tower(s) within adjacent tidal wetlands. The Chickahominy Indian Tribe considers the river an important resource to their heritage and it is sacred to the tribe. The construction of the line may have an adverse effect on Native American resources. This part of the Chickahominy River also includes the Captain John Smith Chesapeake National Historic Trail. Comments from consulting parties to the Section 106 process have focused largely on the potential impacts to this trail in the context of the Surry route. While the status of the trail as a historic property is undetermined, should it be considered an historic resource for the purpose of Section 106, a crossing of the Chickahominy at this location would be a more significant impact to the trail.

The Chickahominy – Skiffes Creek ROW also contains appropriate habitat and known populations of federally and state threatened plant species. Based on field surveys conducted by Stantec, small whorled pogonia habitat is present within portions of the ROW. Database investigations indicate that known populations of this plant may also occur within portions of the ROW as well. In addition, there are several documented bald eagle nests within the vicinity of the route. As such, this alternative is not the least environmentally damaging alternative.

At this time, the use of the Chickahominy ROW would require a new application to the SCC for a Certificate of Public Convenience and Necessity (CPCN) and the filing of a new Joint Permit

Application to the state and federal agencies. The project is estimated to require fifteen months to construct. This estimate does not include time to conduct the necessary environmental studies, additional cultural resource evaluations, final engineering and design of the line, allocation of equipment and materials, and bidding and contracting of the work. While the Chickahominy – Skiffes Creek 500 kV alternative would resolve the identified NERC violations, it cannot do so in the required timeframe. As such, it is not feasible for the project to be completed prior to 2016 thereby eliminating it as a practicable alternative.

3.3 ONSITE ALTERNATIVES

The implementation of the MATS rule will result in the retirement of Yorktown Units 1 and 2 in April 2016. Once these retirements occur, Dominion will be required to import 86% to 99% of its power requirements for the NHRLA from external generation resources. The South Hampton Roads load area, which includes several cities and counties in southeastern Virginia and northeastern North Carolina, is not in a position to make up for this generation deficiency. This load area is also generation deficient and is already required to import 52% to 75% of its power requirement. Therefore, the NHRLA is dependent on Dominion's Extra High Voltage System (500 kV) to transfer bulk power into the load area from available generation resources. Once the connection from the Surry Power Plant property to the proposed Skiffes Creek Switching Station was identified, several other onsite alternatives were considered.

3.3.1 Surry – Skiffes Creek Underground 230 kV Line

Dominion extensively analyzed the potential to construct an underground crossing of the James River using either a single 230 kV line with capacity of 1,000 megavolt-amps (MVA) or a double circuit 230 kV line with total capacity of 2,000 MVA. For reference, the proposed 500 kV line project provides 5,000 MVA of capacity. Each option was evaluated for its electrical effectiveness as well as its environmental impacts. The construction of underground lines from Surry requires a ROW width of 240 feet for a single circuit line and approximately 460 feet for a double circuit line. The construction of a single circuit underground line would require the removal of approximately 18,000 cubic yards (CY) of river bottom. A double circuit 230 kV underground line would result in the estimated removal of 36,000 CY of river bottom. The material would be required to be removed for the installation of splice pits and dredging within the river to install the submarine cables.

As previously detailed, a single circuit 230 kV line cannot solve the NERC reliability violations. Additional alternatives included a combination of an underground single circuit 230 kV line to be constructed in conjunction with the Chuckatuck – Newport News 230 kV alternative outlined in Section 3.2.3.2. This alternative also failed to resolve NERC criteria violations in 2016. Additional projects would be required to fully resolve the deficiencies, none of which could be completed prior to the MATS deadline. Specifically, additional transmission may be required to be constructed in the Chickahominy area to relieve the NERC violations to the north that this alternative does not address. This piecemeal approach towards addressing significant reliability problems in the NHRLA is not cost-effective and would likely result in additional environmental

impacts due to the number and scope of projects required. As with all other 230 kV projects proposed, this project does not resolve NERC violations in a cost-effective manner within the required timeframe. As such, this alternative does not meet the purpose and need and was not considered further.

The construction of a double circuit 230 kV line would face significant challenges from a construction timeline and environmental impact standpoint. This option would require a large portion of river bottom be directly impacted for the installation of the line. The river in this area includes private oyster lease areas as well as underwater archaeological anomalies as identified in an underwater archaeological resources survey completed by Dominion's consultant. Conversely, the proposed overhead line would have minimal impact on the oyster lease areas and will completely avoid impacts to the identified anomalies. In addition to these deficiencies of an underground option, the double circuit 230 kV line still would not resolve all of the identified 2016 NERC criteria violations and would require the construction of two additional projects. This alternative also costs significantly more at $310 to $390 million versus the estimated $60 million for the overhead crossings. As such, this alternative does not meet the purpose and need of the project and was not considered further.

3.3.1.1 Alternative 230 kV Underground Crossing

LS Power, an independent transmission developer, proposed two underground 230 kV options through PJM's RTEP process. One alternative consisted of building a single circuit 230 kV overhead or underground line from the Surry Power Station to the proposed Skiffes Creek Switching Station in combination with the addition of a 500-115 kV transformer at the Great Bridge Substation. The developer ultimately withdrew this proposal in favor of a second option as the "Great Bridge" alternative created more deficiencies than it resolved.

The second alternative offered by LS Power was the construction of an underground or overhead 230 kV line from Surry Power Station to the proposed Skiffes Creek Switching Station with a Phase Angle Regulating (PAR) transformer as part of their solution. Essentially, the scope of this project would be the same as Dominion's preferred alternative for the switching station and the Skiffes-Whealton 230 kV line, but it would allow for an underground crossing of the James River. The PAR device was proposed to be placed in series with the proposed 230 kV line between Surry and Skiffes Creek. However, this alternative was shown to be ineffective as the PAR device and line overloaded and also caused additional facilities to overload. As such, neither of these options resolved the NERC criteria violations, and they were rejected by Dominion as well as PJM from further consideration.

3.3.2 Surry – Skiffes Creek 500 kV Underground (AC)

This alternative was addressed in the Joint Permit Application submitted to the Corps. In summary, the placement of an underground Alternating Current (AC) 500 kV line of this capacity is on the cutting edge of technology and remains highly experimental. The reliability of an underground 500 kV line of the required capacity is unknown given the limited operating experience of this type of line across the world. Underground lines in general present reliability

and operational concerns as the ability to locate and repair damaged lines is significantly more difficult when compared to overhead lines. While visual impacts of the project would be minimized, environmental impacts associated with construction of an underground line would be more extensive than those for an overhead line. In addition, the presence of underwater anomalies has been noted within the project area as a result of an underwater archaeological survey. These anomalies are currently being avoided by the proposed overhead line. It is unclear whether these areas could be avoided or if any adverse effects to these resources would occur as a result of underground line construction.

As demonstrated throughout this document, the project is needed to resolve NERC reliability criteria violations which, if not addressed properly, will have significant social and economic impacts throughout the region. The uncertainty in technology and reliability of an underground 500 kV line precludes it from being a practicable alternative to providing reliable, cost-effective power and was not considered further.

3.3.3 Surry – Skiffes Creek 500 kV Underground (HVDC)

The power system within the United States is comprised largely of high voltage alternating current (HVAC) transmission lines. With changes in technology and an easier conversion of high voltage direct current (HVDC) to AC, DC has become a favored method for transmitting large amounts of power over long distances (typically greater than 100 miles). To assess the potential to alleviate visual impacts associated with the proposed overhead line, a discussion of the feasibility of constructing the project utilizing an HVDC underground crossing of the river is provided here. An HVDC alternative would require the conversion of AC power to DC, the installation of an underground HVDC crossing in the James River, and the conversion of DC power back to AC. During their planning efforts, Dominion considered an underground HVDC alternative but found that due to routing and siting constraints, land acquisition requirements, reliability concerns, cost, increased environmental and cultural impacts and time constraints, this was not a practicable alternative.

3.3.3.1 HVDC Example Projects

Recent examples of HVDC projects in the United States are the Neptune Transmission Project and the Hudson Transmission Project. Both utilized HVDC submarine crossings of waterways to tie into larger, more diverse energy pools resulting in long-term economic benefits. The Neptune project included a 50-mile HVDC line under the Raritan River and Atlantic Ocean to connect Long Island Power Authority (LIPA) to the PJM grid. This project has a capacity of 660 MW which is less than roughly one third the required capability of the capacity injection needed at Skiffes Creek Switching Station (a minimum of 2,000 MW). In the Neptune project case, the cost to construct the HVDC project was justified because the costs of the line project outweighed the cost of building new generation resources in the LIPA Service Territory.

A second project, the Hudson Transmission Project, is a 4-mile submarine crossing of the Hudson River that was constructed using HVDC. The Hudson project is a 600 MW designed system, and provides a new source of energy to New York City through a connection with New

Jersey. Specifically, the project allowed New York City residents access to a larger pool of energy resources at lower cost.

For both the Neptune and Hudson projects, it was more economical and practical to build the HVDC line projects to tap into existing excess generation resources than to build new generation resources in the load area. Access to lower cost generation was a financial benefit to rate payers in the geographic area. In addition, these projects were afforded the luxury of time for planning and approvals as they were not being constructed in association with any NERC or EPA MATS rule compliance deadlines. The Hudson Project entered the PJM Merchant Transmission Queue in July 2005 and was placed in service eight (8) years later. The Neptune Project entered the PJM Merchant Transmission Queue in March 2001 and went in service six (6) years later.

The Surry – Skiffes Creek – Whealton Project does not enjoy either the presence of local excess generation or the benefit of time. As discussed previously, the NHRLA imports a large portion of its power from outside generation, as does the SHRLA, and there is no excess of generation to connect to. Of greater importance is the timeframe required for engineering, review, approval and construction. An underground HVDC project would require resubmittal to PJM, and new applications would be required to be filed with the SCC and the Corps. This would certainly result in completion of the project extending well beyond the required in-service date and lead to rolling blackouts in the NHRLA region.

3.3.3.2 Converter Stations

The use of HVDC typically involves longer lead-time for planning due to the need to locate converter stations on either end of the DC line. In the case of this alternative, a station would be needed on the Surry side of the project, and a second station would be needed on the James City County side of the project. Converter sites generally require 10 to 20 acres for construction and house a converter building that may be several stories tall (5 to 8). Dominion has no property to accommodate a site of this magnitude and therefore, would be required to find and obtain suitable sites for the DC converter stations.

Options for construction of such a site on the James City County side of the project are also severely limited. The proposed Skiffes Creek Switching Station site is not large enough to accommodate both the converter station and the switching station (which would still be required to be constructed under this scenario). The largest area of land available is located on the BASF site. Due to documented contamination and associated liability, construction of any such facility on BASF property is not a feasible option. Additional area may be available to the north of Route 60 and south of the switching station site. However, the submarine cable would either need to be trenched through BASF property, or a transition station converting the line from underground to overhead would need to be constructed. Any large-scale ground disturbance on the BASF site poses a risk of release of contamination into adjacent surface waters and is not desirable from a construction or environmental standpoint.

With the cost of a single converter station being in the range of $300 to $350 million, the construction of an HVDC underground crossing of the James River that adequately addresses the transmission reliability issues would cost well over $1 billion for the necessary underwater cables with the two converter stations. This is significantly more than the $60 million dollars to construct the overhead crossing of the James River.

3.3.3.3 Underground River Crossing

The construction of an underground line, be it HVDC or AC, would result in increased environmental impacts relative to the construction of an overhead line. The line itself would be submarine cable rather than oil-filled pipe, and as such, would need to be trenched or jet-plowed into the river bottom approximately 8 to 10 feet deep. Any viable route would need to avoid the existing gas pipeline located within the river in the vicinity of the project. A navigational red sector and a restricted area associated with Joint Base Langley-Eustis are located to the south of the project area constraining the ability to locate the crossing downstream of the gas pipeline. Locating the crossing to the north of the gas pipeline would require that the submarine cable cross through the pipeline easement or that the line be run underground through Hog Island before exiting to the river. Trenching through Hog Island poses significant impacts from an environmental and cultural resources standpoint.

In the shallow areas of the river, including the Corps dredge spoil disposal area, dredging would likely be required as large vessels and barges would not be able to access these sections of the river to jet in the cable. The capacity requirement of the project would necessitate the installation of 4 to 5 cables. Without specific geotechnical information, the spacing of these cables cannot be estimated, but it is expected that direct impacts to significant areas of river bottom may occur. Dredging may also have an adverse effect on anadramous fish and the Atlantic sturgeon, and will certainly have a more significant impact on the private oyster lease holders within the project area than the proposed overhead line.

3.3.3.4 Conclusion

At a cursory view, an underground crossing appears to be a simple solution to avoiding visual impacts associated with the Surry – Skiffes Creek – Whealton project. However, a thorough examination of the project components and construction requirements of an underground HVDC crossing reveals that this is not the case. Serious routing and siting constraints are present for both the upland and riverine portions of the project. The required converter stations would result in the construction of multi-story buildings on both sides of the river and likely increase the visual impacts of the project. Direct impacts to uplands, wetlands and river bottom would likely increase as well due to the converter stations and disturbance for installation of a submarine cable. Aside from the significant cost associated with an underground HVDC line ($1 billion versus $60 million for the river portions only), the project cannot be constructed prior to the shutdown of Yorktown Units 1 and 2 to avoid rolling blackouts in the NHRLA. Therefore, this does not provide a cost-effective solution, does not meet the project purpose and need of resolving the NERC violation criteria, and is not a practicable solution.

4.0 Selected Alternative

Dominion has conducted an extensive analysis of alternatives to identify the least environmentally damaging practicable alternative that meets the project purpose and need. The only such alternative evaluated is the Surry – Skiffes Creek – Whealton 500 kV/230 kV Line project, the Selected Alternative. Power flow studies clearly indicate severe violations of federally mandated NERC reliability criteria upon implementation of the EPA MATS rule and the retirement of Yorktown Units 1 and 2. The electrical need of the project and the consequences of the No Action alternative are undisputed. If no action is taken, mandatory load shedding, or rolling blackouts, will be instituted across the NHRLA starting in the summer of 2016. The consequences of failing to construct a viable, cost-effective and responsible solution to alleviate these catastrophic consequences are of the utmost importance to the economic and social vitality of this region.

Through a rigorous alternatives analysis including new generation, retrofitting of existing generation, 230 kV solutions, combinations of generation and transmission, and underground alternatives, it has been clearly demonstrated, and independently verified, that an overhead 500 kV transmission solution is required to meet the project purpose and need. The Selected Alternative is the only alternative that was found to fully resolve the NERC criteria violations at the time of retirement of Yorktown Units 1 and 2. It is also the most cost-effective solution that can be constructed within the required timeframes.

The main opposition to the project is a result of the visual impacts associated with an overhead crossing of the James River. The SCC acknowledged in their review that the project will have a negative visual impact that must be considered in relation to the project's need and in choosing between alternatives. However, the SCC found that the only significant visual impacts of the project would be to Kingsmill Resort and Golf Club, which is not an historic property, and Carter's Grove. From the Hearing Examiner's Report (August 2, 2013, p. 156):

> "The proposed Project will have a negative visual impact that must be considered in relations to the Project's need and in choosing between alternatives. However, visual impacts of the proposed Project are mitigated by locating the line where it will not be seen from most areas of the Historic Triangle likely to be visited by the public. Where the overhead crossing of the James River can be seen from the Colonial Parkway or Jamestown Island, it will be distant (approximately 4 to 6 miles away), and tend to blend with other development that can be seen from those areas. Moreover, the added capacity of the 500 kV transmission line, over time, should serve to reduce overall impacts by reducing the need for additional transmission projects associated with a less-robust or piecemeal approach."

The SCC also considered visual impacts to the James River itself. The portion of the river in the vicinity of the crossing has been described in a range of terms including unspoiled, pristine, industrial and developed by opponents and proponents to the project. Modern day intrusions

are no doubt visible from Jamestown Island, the Colonial Parkway and Carter's Grove. These intrusions include the Surry Nuclear Power Plant and associated transmission towers, the Ghost Fleet, the sewage treatment plant at Kingsmill, the Kingsmill marina, and portions of BASF and Busch Gardens. The SCC determined, based on photosimulations and the testimony of Mr. McCoy, President of MAE, that the section of the river crossed by the Project cannot be considered "pristine" and is not the same view enjoyed by Captain John Smith (Hearing Examiner's Report, August 2, 2013, p. 139).

Consideration was given to the impacts on the James River as a "Historic River." Pursuant to §10.1-419 of the Code of Virginia, a twenty-five mile section of the James River is designated as an "Historic River," and provides that in the "planning for the use and development of water and related land resources...full consideration and evaluation of the river as an historic, scenic and ecological resource should be given before such work is undertaken." A portion of the Project is within the designated area where the line begins to cross the river at the Surry Nuclear Power Station. The Hearing Examiner's Report states (August 2, 2013, p. 139):

> "Given the presence of the Surry Nuclear Power Plant, I find that the Surry-Skiffes Creek Line would not change the character of the James River where it crosses the portion of the James River designated by §10.1-419 of the Code of Virginia as an "Historic River." Furthermore, based on its distance from historic resources such as Jamestown Island, the Colonial Parkway, and even Carter's Grove, and based on the screening of Hog Island for views from Jamestown Island and the Colonial Parkway, I find that the portion of the Surry – Skiffes Creek Line crossing through the portion of the James River designated by §10.1-419 as an "Historic River" will be the least visually impacting portion of the James River crossing of the Surry – Skiffes Creek Line. Consequently, I find that the proposed Project complies with §10.1-419 of the Code."

Additional information regarding impacts to cultural and historic resources pursuant to Section 106 of the National Historic Preservation Act is being provided under separate cover for review.

Through the alternatives considered, Dominion and the project team have clearly demonstrated that any viable project must be in the form of a 500 kV transmission line. This determination was verified multiple times by independent analysis. No generation solution, 230 kV solution or combination of 230 kV lines and generation were able to meet the purpose and need of providing cost-effective, reliable power by April 2016. Likewise, alternative technologies for an underground crossing of the James River are not practicable. As such, the Selected Alternative is the only remaining alternative that can achieve the required results, the Surry – Skiffes Creek – Whealton project. Dominion is committed to providing appropriate, reasonable mitigation to compensate for any adverse impacts to environmental or cultural resources determined by the Corps as a result of their review of this project.

5.0 References

The following materials from the SCC hearing and proceedings are incorporated into this response by reference. These materials have been provided under separate cover. A table of contents of the reference volumes is provided below:

5.1 VOLUME 1

Section 1: June 11, 2012 Volume I – Application & Appendix

Section 2: June 11, 2012 Volume II – Testimony & DEQ Supplement (Direct Testimony of Hathaway, Nedwick, Cox, Spears, Harper & Lake)

Section 3: June 11, 2012 Volume III – Environmental Routing Study Appendix A-F

Section 4: June 11, 2012 Volume IV – Environmental Routing Study Appendix G

Section 5: June 11, 2012 Volume V – Environmental Routing Study Appendix G (cont.)

Section 6: June 11, 2012 Volume VI – Environmental Routing Study Appendix H-J

5.2 VOLUME 2

Section 1: August 16, 2012 – Revision to Application

Section 2: September 18, 2012 – Revision to Appendix & Spears Testimony

Section 3: September 19, 2012 – Supplemental Testimony

Section 4: February 4, 2013 – Letter of Witness change (Allen to Cox)

Section 5: Public Volume I: Rebuttal Testimony & Exhibits (Rebuttal Testimonies of Hathaway, Nedwick, Herling, Allen, Thomasson, Faggert, Kelly & Swanson)

Section 6: Public Volume II: Rebuttal Testimony & Exhibits Cont. (Rebuttal Testimonies of Harper, Twiss, Lake, Wolverton, Taylor, Brucato & Erdreich)

Section 7: Public Volume III: Schedules & Studies 1-6C

Section 8: Public Volume IV Schedules & Studies 7A-8

Section 9: Public Volume V Schedules & Studies 9-13C

Section 10: Public Volume VI Schedules & Studies 14A-26a

Section 11: April 3, 2013 – Revisions to Rebuttal Testimony

Section 12: April 3, 2013 – Revisions to Appendix

5.3 VOLUME 3

Section 1: January 11, 2013 – Prefiled SCC Staff Testimony (Testimony of Chiles & McCoy)

Section 2: August 2, 2013 –Approval and Certifications of Electric Facilities (Hearing Examiner's Report)

Section 3: November 26, 2013 – Order for Approval and certification of Surry –Skiffes-Whealton (Final Order)