DVP's Proposed "Surry-Skiffes Creek Project" – Issues and Alternatives

Addendum Report

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Executive Summary

This report supplements information in NPCA's previous submittal of 13 November 2015 to the US Army Corps of Engineers (USACE) regarding Dominion Virginia Power's (DVP) proposed "Surry-Skiffes Creek" 500kV overhead transmission line across the James River near historic Jamestown. It adds clarification, additional information, and analysis to that report- incorporated here by reference.

Further study and discussions with Dominion Virginia Power (DVP) and USACE have confirmed and reinforced the previous report's findings:

1. **Dominion overestimated peak load and economic growth projections, compared to actual peak load and economic growth since 2011.**
2. **Dominion's evaluation of alternatives and related costs, especially submarine cable costs, are outdated and inadequate, resulting in Dominion's overestimating these costs.**
3. **Dominion underestimated the potential impact of increased distributed solar photovoltaics to help meet demand.**
4. **Dominion underestimated the potential impact of demand side management and energy efficiency to help reduce demand, especially peak demand.**
5. **In addition to these findings, strong concerns raised by the National Park Service and the interested public call into question the purpose and need for the project as set forth by Dominion, and support a decision by the USACE to require completion of a full Environmental Impact Study to provide further analysis.**

The report submitted today further finds:

1. **In the near term (one to five years), there appears to be no operational crisis or threat of load shedding on the peninsula because peak loads now are being managed without Yorktown Units 1 and 2 operating. A review of actual operational data reveals decreasing reliance on production from the Yorktown power plant.**
2. **Three of Dominion's largest customers in the North Hampton Roads Load Area are federal facilities, and electricity use at those facilities has decreased nearly 15 percent in the last four years.**
3. **At four times the total capacity of the Yorktown facility, the capacity of the proposed Surry-Skiffes Creek line is excessive. The proposed line would be 5000 MVA, which can carry up to 5000 MW, compared to 1140 MW total capacity of the Yorktown Station.**
4. **The proposed capacity has resulted in overdesign of Dominion's preferred project and of alternatives, and has had a disproportionately large impact on submarine cable costs.**
5. **After all Yorktown units are decommissioned, a project to provide additional transmission capacity will be needed for system reliability. A submarine cable system would avoid major**

environmental impacts and security vulnerabilities. Costs of such a system, designed for a more reasonable power capacity, would be far lower than Dominion's estimate for its submarine cable alternative.

Since our November report, the National Park Service has urged the USACE to deny the permit application and to require a full Environmental Impact Statement (EIS) to determine the best approach (letter included in Appendix D), due to the unacceptable damage this project would cause to unique and nationally significant historic sites. Other issues raised by the public and consulting parties needing further analysis include unanswered questions regarding the proposed project's impacts on natural resources, endangered and threatened species, tourism, and private property values.

In a January 2016 meeting among USACE, DVP, NPCA, and PERI, DVP representatives indicated that they had performed updated load-flow studies in which the projected power shortfall on the peninsula upon retirement of Yorktown Units 1 and 2 had increased from 240 MW to 375 MW. DVP agreed to provide detailed power demand data to justify the large capacity of the line, but has not done so as of today's date. None of the information available to our engineers to date supports such a large increase in the load shedding estimate.

Peak Loads – Forecast and Management

Dominion's original proposal for the 500 kV overhead power line was based on overestimated load growth and the prediction that the retirement of Yorktown Unit 1 would trigger load shedding during a contingency event. The predicted shortfall has not materialized, and it is likely that these shortages could be delayed for years by deployment of residential and commercial solar photovoltaic (PV) systems, additional demand side management (DSM) and energy efficiency improvements.

Both actual and projected summer peak loads have decreased significantly since 2011, the base year for the original proposal. DVP's load flow studies use data from the regional transmission organization, Pennsylvania-Jersey-Maryland (PJM) that includes DVP service territory (the "DOM zone"). The simulation of peak loads in DVP's load flow studies uses data from the PJM Annual Load Forecast Report (LFR), which is published in January of each year and provides 15 year projections of summer and winter peak loads. The DVP load flow analysis uses peak loads from the 2012 PJM LFR, and DVP allocates portions of the load to different balancing areas within the DOM zone.

The DVP analysis of 2012 projected a shortfall (peak load shedding) of 220 – 240 MW in the North Hampton Regional Load Area (NHRLA) upon decommissioning of Yorktown Units 1 and 2. However the most recent PJM LFR was released in early January 2016 and shows an actual decrease in the weather-normalized peak loads from 2000-2015, shown in **Error! Reference source not found.** in the dotted red ine. The actual historical peaks (jagged black line) show an all-time high in 2011 and then lower peaks in all subsequent years. It should be noted that weather normalized peaks have not changed much in ten years, and are currently well below the record highs of 2007 and 2011.

Error! Reference source not found. shows the forecasts from PJM 2012 and PJM 2016 on the same raph for ease of comparison. There are two striking differences: the new forecast is about 9 – 10 percent lower in 2015-2018, and the gap grows larger after 2019 due to reduced growth rates in the latest forecast. It should be noted that these trends do not include the reductions in peak load that could be achieved with more aggressive deployment of solar PV, DSM and efficiency.

This DOM zone reduction equates to a proportional reduction in peak loads for NHRLA in 2015/16. DVP's 2012 testimony to the State Corporation Commission (SCC) forecast summer peak loads of 2183 MW for 2016, so a 10 percent reduction equates to a drop of about 218 MW of load. This is only 2 MW short of the lower bound of Dominion's projected load shedding (220-240 MW) following decommissioning of Yorktown Units 1 and 2. This indicates that the need for load shedding has receded significantly.

In a meeting on January 8, 2016 among the USACE, DVP, NPCA, and PERI, DVP staff stated that more recent load flow studies are currently underway using PJM 2016 LFR peak loads, and the result is that the estimated load shedding has increased to 375 MW. That figure represents a 70 percent increase from DVP's previous estimate of at least 220 MW of estimated load shedding -- despite a nearly 10 percent drop in peak load forecast. DVP staff stated that the original load shedding estimate was for planning purposes only, in order to demonstrate to the SCC that NERC reliability violations were triggered in the load flow studies. They also stated that the scheduled outages in their most recent, unpublished analysis were significantly different than those in the original. This difference was cited as a primary cause of the change in the load shedding estimate, and not due to changes in status or operation of Yorktown units. Nothing in the information available to PERI's researchers supports the higher load shedding projection, and as of this date DVP has not followed through on its commitment to share this information.

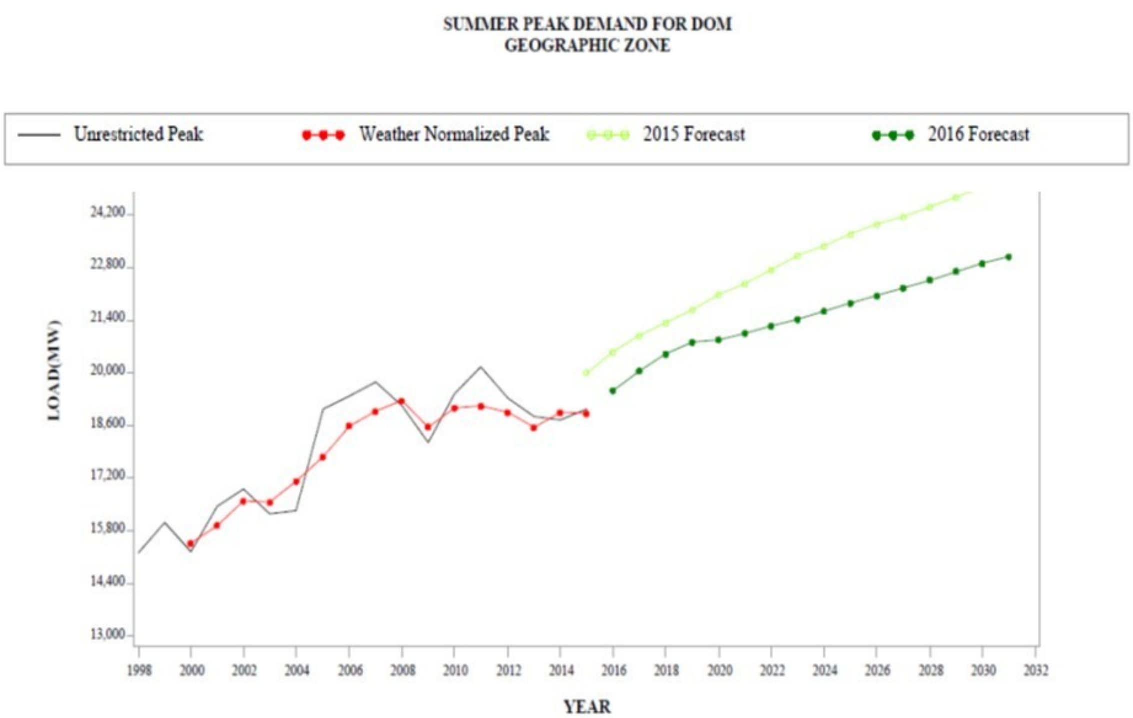

Figure 1- Peak Load Forecasts DOM Zone, from PJM 2016 LFR

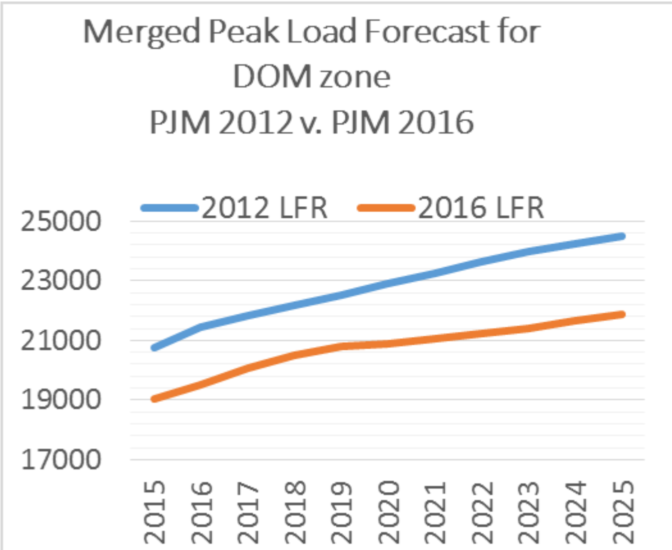

Figure 2- PJM 2012 Forecast and PJM 2016 Forecast for DOM zone shows significant reductions in projected peak demand

Yorktown Operations – Full Capacity No Longer Used for Summer Peaks

To determine how power is managed on the peninsula, and how much power is generated locally during peak periods, PERI accessed Yorktown's actual emissions data which DVP provides to EPA to comply with clean air regulations. Yorktown is one of DVPs highest cost and highest emissions facilities, so it is normally operated only during periods of peak demand, which nearly always occur in summer, but occasionally occur during winter cold snaps. During summer, lines can overheat more easily, so system capacity is lower. Because line ratings are higher in winter, there is less threat of load shedding. For these reasons this analysis did not consider winter peaks, which rarely exceed summer peaks.

The vast majority of summer peak loads occur during July and August, so this analysis looked at the most recent five years of data - from July and August of 2011 – 2015. Thirteen events were identified when Yorktown Unit 3 was generating power during those periods. This event definition was selected since DVP has identified Unit 3 as a plant that only operates during peak demand periods. Appendix A contains time series graphs for all 13 of these high-load events, and all units operations during the study period.

The analysis revealed a distinct change in operations of Yorktown during the last three summer seasons. Since July 2013, all three units are no longer needed to meet peak demand.

Figure 3 shows three sample graphs that illustrate this change. The vertical scale shows MW and the horizontal scale is the hour number of the event period. The first graph shows typical operation before July2013 (July 5-6, 2012). The Unit 1 line (blue) is sometimes overlaid and obscured by the Unit 2 line (orange) since the units are often run in tandem. For this event and all of the first seven (out of thirteen) events, up until July 2013, all three units were used in concert. Units 1 and 2 follow a roughly bi-modal 24 hour cycle and Unit 3 mostly follows load during daily peaks, as illustrated in the first graph. For the four year analysis of peak summer season, Yorktown total generation reached or exceeded 1100 MW in one event in August 2011 and one event in July 2013. Since then, it has never exceeded 840 MW in July or August (Unit 3 capacity).

The second graph shows typical solo operation of Unit 3 operations after July 2013 (August 5-8, 2013). Units 1 and 2 are cold (zero emissions) and Unit 3 (gray line) is operating solo. This event was a distinct change from past operational patterns. From this point forward, Unit 3 was operating solo during all of the remaining six events, up through August 2015.

The third graph shows a typical sample of Unit 1 and 2 operations after July 2013 (July 3-9, 2014). A comprehensive examination of operations of Units 1 and 2 showed that neither of them were running (zero emissions) within 48 hours of the start or ending of any of the six Unit 3-solo peak load events. Further, all periods were identified in July and August 2014 and 2015 when Unit 1 and/or Unit 2 were operating. These four periods are shown in the last four graphs in Appendix A. The data show that Unit 3 was not operating during these periods, and was not operating within 48 hours of either side (shoulder) of these periods. Since Units 1 and 2 need about 48 hours to warm up before taking significant load, the data contradict a DVP statement[1] that Units 1 and 2 are often needed as spinning reserves to support Unit 3 during the "shoulder periods" leading up to, and following closely after, peak events.

The fact that Units 1 and 2 have not been operating within 48 hours of Unit 3 during summer peaks since July 2013 seems to indicate a reserve of unused generating capacity on the peninsula is no longer needed. This was likely not anticipated in 2012, when DVP projected that brownouts were going to occur 80 days per year upon shutdown of Units 1 and 2. Since July 2013, the highest level of generation on the peninsula during summer peaks was that of Unit 3 operating solo (around 820 MW). Unit 3 is limited in summer to about 840 MW, and rarely generates over 800 MW during peak periods. This means that the four existing transmission line circuits into the peninsula are supplying approximately 1,200 MW, or 60 percent of the load, assuming a peak summer load of 2,000 MW for NHRLA.

[1] Personal communication of 8 January 2016 with DVP staff at Norfolk USACE office

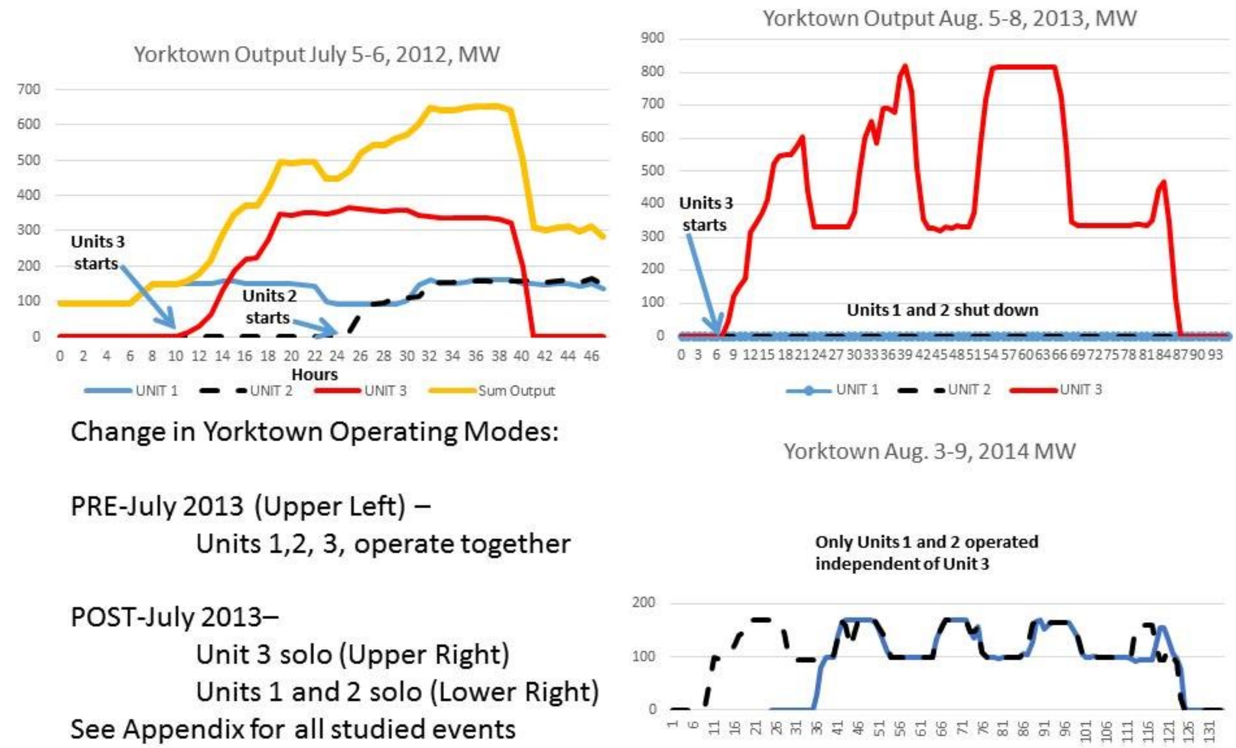

Figure 3- Yorktown Output- Representative Samples, showing change in Yorktown operations since July 2013. In numerous cases, Yorktown Units 1 & 2 were not in operation yet no brownouts occurred.

System Reliability Studies, NERC Standards, and Peak Loads

As a member of PJM, DVP is legally bound to ensure that their system meets reliability standards from the North American Electric Reliability Council (NERC), an industry group that sets standards for long term transmission planning to ensure system reliability. A brief background discussion of NERC Standards, system reliability, and load flow modeling is included as Appendix B.

NERC does not define a specific methodology for doing reliability studies (which are based on load flow studies), which leaves a great deal of latitude for system operators to choose from different assumptions, inputs, and models in their analyses. Scheduling of outages, designation of "at risk of retirement" facilities, allocation of simulated loads to different balancing areas, and use of data from non-representative historical periods, can all materially affect the outcome of load flow and reliability studies. Although it has not yet been made clear why DVP's load shedding estimate increased by 70 percent, it is clear that NERC's process allows system operators plenty of leeway to get multiple results.

As the operational analysis showed, since July 2013, peak summer loads on the peninsula have been fully served using only Yorktown Unit 3, without Units 1 and 2. DVP's publicly-available load flow studies also indicated that a 230 kV line from Surry to Skiffes would overload the 230 kV system coming in to the region. However, this problem potentially could be avoided by simply installing a transformer to connect to the existing 500 kV system. Only a load flow study can truly determine the performance of such a design, but a 230kV, double circuit system that connects to the 500kV line at Surry was not even considered in DVP's analysis.

PERI's updated analysis, using the most recent PJM forecasts and recent Yorktown operations data, indicates that the peninsula would not experience load shedding upon shut down of Units 1 and 2, even during extreme summer peaks.

Under FERC Order 1000[2], cost allocation methodologies are implemented to share transmission project costs more equitably between the utilities that benefit. There is a different cost-sharing formula used for transmission projects over 345 kV. This may provide some incentive for Dominion to prefer 500 kV projects since the costs are allocated differently for larger projects.

Eventually, DVP has stated that all three units at Yorktown will be retired, due to their age and emissions. After Units 1 and 2 are retired, upon retirement of Unit 3 NHRLA would be in violation of NERC reliability standards, regardless of the change in peak load forecasts. In the company's latest Integrated Resource Plan, DVP's estimate for closing Unit 3 is in 2020, although there is some leeway in that date as the plant was not scheduled to close until 2022. Compliance with carbon emission reduction rules under the Clean Power Plan (CPP) is left up to the states in detail, and there are pathways identified in a previous IRP that keep Unit 3 open until at least 2022. This removes any immediacy of the issue and allows time for a more thorough investigation of load flow on the peninsula and how it can best be managed.

Demand Side Management – Large, Untapped Potential

Demand Side Management (DSM), also called load management or demand response, is a rapidly growing component of grid operations across the nation and around the world. Utilities are finding that the need for new transmission capacity and for dirty and/or expensive "peaker" power plants can be greatly reduced or eliminated if peak demand can be reduced. The following is an excerpt from the NERC Reliability Assessment Guidebook of August 2012 – designed to help system planners and operators develop accurate reliability assessments.

*–"In spite of the challenges, DSM resources are legitimate resources to be included in current and future resource evaluations. …….. contrary to supply resources they start to provide benefits immediately. ……In the past, DSM resources in resource adequacy evaluations have usually been interruptible loads at a small number of large industries and amounted to only a few percent of total resources. …. Since the 1980's, the number and type of DSM programs has been increasing. In the future DSM resources may be **10 percent or more of total resources**."*

[2] http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf

At the retail/residential levels, DSM is being accomplished primarily through incentive programs to reduce energy use during peak loads, or with basic tiered pricing structures, where customers pay a higher rate during peak periods. At the wholesale/industrial level, DSM assets are registered by DVP with PJM and classed into several categories according to their response time and availability. These assets respond to either price signals or direct commands from DVP, so they are relatively straight forward to control and quantify. According to the latest PJM estimates, there is currently about 1,300 MW of "member" (registered) DSM capacity in DOM zone, and according to DVP[3], there are only about 13 MW in NHRLA. For DSM to equate to 10 percent of total peak load as envisioned by PJM, this would increase to about 200 MW of DSM in the NHRLA. This decrease in demand could be partially offset by new customers. DVP has indicated that since 2012, about 7,800 new customers have been added bringing the total to about 290,000 in the Dominion service territory. The impact of this incremental addition is not considered significant.

At the retail level, local utilities have voluntary programs that allow them some control of homeowners HVAC or water heater systems so they can be cycled on and off to manage peak loads. The programs are designed so that the effect on one customer is barely noticeable but the cumulative effect is significant in terms of peak demand reduction. Figure 4 provides a summary of active retail DSM programs (2014) in Virginia and neighboring states. Enrollment rates vary, from 7% in DVP to 80 % in Delmarva Power and Light – Delaware territory. Load drop per enrollee also varies, from about 160 watts in PEPCO to 1 kW in DPL-MD, and can go as high as 2 -3 kW, as in the Nevada eMpowr program, which has aggregated 100 MW of DSM from 50,000 program participants.

Some rough calculations can provide a good estimate of the potential for DSM in NHRLA. DVP serves over 280,000 customers in the NHRLA. Assuming a conservative participation rate of 25% yields an estimate of 70,000 enrollees. An HVAC cycling program using the smart meters DVP has already tested in their pilot program could easily achieve a 1 kW load drop per enrollee. Based on this conservative estimate, 70 MW of retail DSM could be aggregated from individual customers within NHRLA in a very short time, and 100 MW of DSM (~5% of peak load) could easily be met or exceeded with an aggressive campaign and supportive policies. Even this number may be conservative based on a NERC assessment of DSM potential, cited below.

[3] Oral statement by DVP staff, 8 January 2016, Norfolk USACE office

EDC/state	Customers	Enrollees	MW	Participation Rate	kw/ enrollee	Notes
DPL- Md	201,000	32,000	33	16%	1.03	more Comm. & Indust.
DPL- De	305,000	244,000	78	80%	0.32	
Rap E.C.	160,000	40,000	8	25%	0.20	
PEPCO	815,000	363,000	59	45%	0.16	
DVP	**2,300,000**	**165,000**	**65**	**7%**	**0.39**	**lowest participation rate**
NV E-Mpowr		50,000	100		2.00	1- 3 kW / enrollee
NHRLA	**280,000**	**70000**	**70**	**25%**	**1.00**	**Reasonable and quickly implemented***

Figure 4- Sample of Active (20140 DSM Programs in MD, DE, VA Area, showing potential of retail DSM Programs. Dominion Virginia Power is underutilizing DSM programs.

*- Estimate uses Rap.E.C. participation rate and DPL-MD load drop per enrollee
Data Source - EIA Demand Response 2014 https://www.eia.gov/electricity/data/eia861/
Rap. E.C. = Rappahannock Elec. Coop DPL = Delmarva Power and Light

Solar PV – Large Untapped Potential - Reduces Transmission Requirements

Using distributed residential and commercial solar photovoltaic (PV) energy can significantly reduce demand and consequently transmission requirements for power delivery from DVP. PERI's previous submittal to NPCA/USACE described that potential by 2030 for deployment of up to 80 MW of solar PV distributed generation in residential and commercial scale applications. Distributed generation has the distinct advantage of generating power at the point of use so there are no transmission losses, which can be as much as 10 percent. In reality this new distributed generating capacity is likely to be delivered much sooner due to new federal incentive programs. The EPA is providing a Clean Energy Incentive Program (CEIP) to reward early investments in renewable energy (RE) generation and demand-side energy efficiency (EE) measures that generate carbon-free MWh or reduce end-use energy demand during 2020 and/or 2021. State participation in the program is optional and Virginia is still developing its Clean Power Plan now being implemented by EPA.

Through this program, the EPA will make additional allowances or Emission Rate Credits (ERCs) available to states to encourage early pollution reductions from zero-emitting solar or wind power projects and EE projects. The EPA intends for the CEIP to have a reserve for wind and solar projects and a reserve for

EE projects in low income communities, and is taking comment in the federal plan on several aspects of the CEIP, including the size of these reserves. The EPA is providing additional incentives to encourage EE investments that are implemented in low-income communities.

The CEIP specifically incentivizes solar and other RE projects because these technologies can be implemented relatively quickly and because stakeholders were concerned that the Clean Power Plan could potentially shift investment away from these zero-emitting technologies.

Federal Facilities Reducing Electricity Demand

On January 27, 2016, the U.S. Department of Energy (DOE) announced $2.85 million in funding for four projects that will advance the development of renewable energy technologies at facilities across the federal government. As the nation's largest single user of energy, the federal government is leading by example and these projects will reduce energy usage and consequently carbon emissions, while strengthening America's economic, energy, and environmental security. This award did not include any facilities in the NHRLA, but serves as a model for federal agencies that do have offices in the Hampton Roads area including Departments of State (Customs), Agriculture, and Justice, in addition to Energy and Defense.

The federal agencies are responding to legislation and a series of Presidential Executive Orders. Over 30 years ago, federal agencies were first directed to track and improve their energy management practices.[4] More recently (2007), the Bush administration issued a key Executive Order titled, "*Strengthening Federal Environmental, Energy, and Transportation Management.*" Subsequently, goals were set by each federal agency to improve energy efficiency and reduce greenhouse gas emissions through reduction of energy intensity, and a progress tracking system was established. Energy usage trends are tracked for agencies by the Department of Energy, Federal Energy Management Program (FEMP).

Three of DPV's largest customers located in the NHRLA are under Departments of Defense and Energy: Joint Base Langley – Eustis, Naval Weapons Station Yorktown and the DoE, Thomas Jefferson National Accelerator. Energy usage at these facilities has decreased nearly 15 percent in the last four years. Detail statistics are shown in Table 1.

[4] National Energy Conservation Policy Act (NECPA) of 1978, Section 548, in Title 42, U.S.C., Section 8258 [42 U.S.C. §8258], which requires Federal agencies to describe and improve their energy management activities

Table 1

Federal Facilities Annual Energy Usage (Bbtu)
Hampton Roads Area- Showing
Reductions in Use

Facility	**FY-2011**	**FY-2012**	**FY-2013**	**FY-2014**
Department of Defense				
Joint Base Langley – Eustis	1363	1127	1284	1281
Weapons Station Yorktown	286	203	229	218
NSA Hampton Roads	572	984	964	949
Little Creek Amphibious Base	596	719	761	711
Oceana NAS	730	678	712	700
NAVSTA Norfolk	2179	2032	1980	1871
NOSC Midland Norfolk	80	80	80	80
NSS Ship Yard Norfolk	1128	1018	470	446
Total	6934	4527	4003	6256
DoD Reduction				9.8%
Department of Energy				
Thomas Jefferson National Accelerator	486	447	322	321
DoE Reduction				34.0%
Total for 3 Federal Facilities in NHRLA (GreenHighlight)	2135	1777	1835	1820
NHRLA Reduction				14.8%

Source: DoD Annual Energy Management Reports for FY-2011 thru FY-2014 and DOE FEMP.

Energy usage by 3 federal facilities in NHRLA has dropped almost 15%.

Submarine Cable Alternatives – Significant Advancements Require a Second Look

In the near term (1-5 years) there appears to be no operational crisis or threat of load shedding on the peninsula since peak loads currently are being managed without Yorktown Units 1 and 2. In the long term (6-10 years) the decommissioning of all three units at Yorktown undoubtedly will place the peninsula in violation of NERC reliability standards. However, this analysis strongly suggests that any operational issues can be resolved by simply replacing the capacity of Yorktown with a transmission link of nearly the same capacity, roughly 1100 MVA. In order to provide even greater reserve capacity, add redundancy, and resolve long term NERC reliability issues, a system providing a total capacity of 2000 MVA could be designed and installed.

According to the Stantec/DVP report of November 2014, a 230 kV double circuit could provide this power. Stantec indicated that the double circuit would provide 2,000 MVA, using a 460 ft. wide right-of-way (ROW). Using new HDD techniques, it is possible this ROW, and the costs, could be cut in half. This is discussed below.

DVP Submarine Alternative Overdesigned

In their June 2012 testimony to the SCC, (Vol II, p. 21) DVP (Nedwick) summarized the state of the art (as of 2011) and also confirmed that 2000 MVA was the minimum required capacity of the Surry-Skiffes Creek 500 kV line:

"Underground lines at 500 kV have only been installed in a few places around the world and have been limited to 1000-1200 MVA. None has been installed with the minimum required 2000 MVA capacity of the Surry-Skiffes Creek 500 kV line. The only 500 kV underground in the U.S. is a short power station connector line installed between a hydroelectric generation plant and an adjacent switchyard."- Nedwick, SCC 2012 Vol.II, p. 21).

Despite the minimum required capacity of 2000 MVA, DVP's current plans call for a system with 5000 MVA capacity (Stantec I, page 3.21). To handle this extreme capacity (more than double the peak summer load for all of NHRLA, and over 4 times the total capacity of Yorktown), DVP's submarine alternative included nine cables, for a total rating of about 5000 MVA. The extra cables require much greater right of way (ROW) width across the river, which severely restricted the siting options. DVP estimated the cost of the crossing at $310 M - $390 M in the 2012 SCC testimony, but in recent documents, the estimate has been as high as $400 M.

Since 2012, the state of the art has advanced significantly for high voltage submarine cables, pushing back limitations and reducing costs, as evidenced by the survey of recent projects referenced in the following section and detailed in Appendix C.

Reasons to Underground/Submarine

In addition to eliminating the visual, economic, and environmental impacts associated with towers, compelling reasons to use a submarine cable vs. tower suspension include improved designs, reduced risk of sabotage, reduced risk of failure due to extreme weather, and reduced risk of costly litigation.

Improved Submarine Cable Designs and Installation Techniques

This section summarizes several recent projects to install buried and submarine cable systems in the 300-500 kV range. It discusses each project briefly as it relates to the proposed DVP project.

PERI surveyed recent, similar transmission projects, revealing that the costs for a 2000 MVA system would be much less than DVP's 2012 estimate for a submarine cable system, due to lower capacity requirements and to recent advances in submarine cable designs and installation techniques.

Over approximately the last five years, developments in the high voltage cable industry have allowed the use of higher voltage cables in subterranean and submarine installations. The need for secure, robust, efficient power transmission cables for the offshore wind industry has been a key driver of this development. Another driver has been the need to avoid the harmful impacts associated with tall towers and river crossings. In the past, heat dissipation, water and current leakage, and corrosion concerns made a very strong case for suspending cables from towers. In the past, a submarine crossing longer than a mile had to use plow and trench methods which are expensive and entail significant environmental impacts during construction. With recent advances in both cable design and installation techniques, including horizontal directional drilling, better longitudinal moisture barriers, durable insulating materials, and improved heat shedding characteristics, the cost and capabilities of submarine cables have greatly improved, as demonstrated by numerous installations around the US and abroad. These cases are detailed in Appendix C.

Advances in Horizontal Directional Drilling River Crossing

Several of the projects investigated utilize horizontal directional drilling (HDD). In this process, a long, flexible boring rig is used to drill a hole underground, and a pipe is pulled through to serve as a conduit. Cable is then pulled through the conduit. Friction limits the distance that a large cable can be pulled through a conduit. As length increases, so does cable weight, friction, and pulling tension. The cable armor must be strengthened for the cable to take more pulling tension, but that increases weight and friction and requires ever greater pulling tension. The maximum length is also a function of the maximum burial depth and curvature of the route. For cables in the range of 230 kV-500 kV, in 2011, this limit was on the order of 5000 – 6000 feet, based on similar projects. To achieve the high pulling tension, steel pipe conduit was required, but this sapped energy through the electric field of the cables and reduced their effective capacity, necessitating more cables, and driving up costs.

However using new materials and techniques, HDD installations exceeding 11,000 feet are now in operation in New Jersey (see Cable Appendix) and other systems are planned for similar distances[5]. Instead of steel conduit, the longer pulling distance is achieved with double fused PVC pipe sections that do not affect the cable's carrying capacity. The beads at the inside joints are removed to provide a smooth inner wall and a special lubricant is used to reduce friction. This technique removes the need for marine operations, including any plowing or trenching that would disturb the river bottom and disrupt vessels and surface activities. HDD technology requires no surface excavation except a small area on the shore to set up the rig and start the borehole. It also greatly reduces the ROW, since there is no need to separate the cables far enough apart to repair them from a boat. In some cases, multiple cables can share a conduit. HDD borehole separations are typically on the order of 20 feet, regardless of water depth. HDD repairs are performed by simply pulling the cable out of the conduit.

[5] http://www.undergroundsolutions.com/papers/WM-T4-02.pdf

The ability to reduce the cable ROW and avoid significant impacts to vessel traffic and submerged habitat would expand the siting possibilities and reduce the risk of permit application denial, public opposition, and litigation. The use of HDD also cuts cost by more than half compared to a typical hybrid installation using HDD plus trench and plow.

Rough Cost Comparison - Submarine Cable Costs Overestimated

For an analysis of a very similar cable system crossing the Delaware River, the PJM consultant UC-Synergetics (UCS) concluded that, "The overall estimated costs between the five options presented varied substantially between companies and between proposals. The estimated cost range went from a low of $116.3 Million to a high of $269.2 Million. These cost estimates can be compared to Standard Industry Unit Measures of cost per mile shown in the table below [*Figure 8*].

Figure 5 is taken from a PJM funded report of 2014[6]. It shows the standard unit costs used by PJM as a starting point for estimating transmission project costs. The cost for a submarine 230 kV circuit is $35M per mile, for a single circuit. At most, a double circuit could cost twice as much, but even at $70M per mile it would still be about half the cost of Dominion's estimate for the crossing ($390M).

Cost Estimates of Industry Standard Unit Measures:

Transmission Components	Dollars	Units
230kV overhead transmission	$3,500,000	per mile
230kV underground transmission	$10,500,000	per mile
230kV submarine transmission	$35,000,000	per mile
230kV transmission line dead-end structures	$300,000	per unit
Aerial Delaware river crossing	$100,000,000	per crossing (Cost supplied by PJM)

* Notes:
- Costs can vary widely based on actual site specific locations, requirements and conditions.
- Cost estimates are budgetary installation costs only based on past projects and experience.
- Factors that may significantly increase these installation costs include:
  - Environmental, Regulatory Licensing Costs
  - Permitting costs
  - Land purchase costs
  - Civil work including site preparation, grading, wetland mitigation, and other encountered conditions
  - Rock excavation.

Figure 5- PJM Standard Unit Costs for Transmission Planning- Lower than Dominion Estimates

DVP also looked at an alternative developed by LS Power called the "Surry-230 kV Partial" that included a 230 kV submarine link and a Phase Angle Regulator (PAR) for an estimated cost of $99 million. The assumption was that both HDD and plow trenching would be required. No new transformer would be required at Skiffes Creek since the line could tap into the existing 230 kV system. DVP's analysis stated

[6] Allen, Glen N., P.E., *Constructability Analysis of Artificial Island Delmarva Peninsula Project Proposals,* Page 5, UC Synergetics for PJM, April 30, 2014

that the 230 kV link would not solve reliability issues since it would result in overloading the 230 kV system on the Surry side of the river under contingency conditions. Other reasons given for dismissing the idea were the time required for implementation and remaining NERC violations related to overload of the 230 kV system on the Surry side of the river. However, to avoid overloading the 230 kV system on the Surry side, the line could be stepped up to join the 500 kV system at Surry. A load flow analysis would be required to definitively test the system performance and reliability, but this alternative was not considered by DVP.

Reduce Security Risk Exposure

A tower crossing of the James River would be one of the most vulnerable pieces of DVP's 500 kV system at a critical point for national security. Failure would impact many DOD facilities, including a base where nuclear weapons are stored. The ~ 75 degree hard angle in the proposed cable path within the James River where the alignment changes from N/S, along the Hog Island shoreline, to nearly E/W, crossing the river results in high transverse loads on this anchor tower structure. This tower would be vulnerable to a terrorist in a small boat with an acetylene torch. This act alone would not bring down the NHRLA system, but in concert with attacks on the proposed Skiffes Creek station or another transformer, the risk is not insignificant. A buried/submarine cable system would have greatly reduced vulnerability.

A potential lower cost river crossing option not yet fully analyzed could be connected at Fort Eustis. This is the narrow area of the river as shown in Figure 6. With recent advances in HDD, the entire crossing may be possible using that method, which reduces cost and impact compared to plow trenching across the river. The cable could also be undergrounded for the segment connecting to the Surry switching station. The eastern termination would be at Fort Eustis, a more secure location.

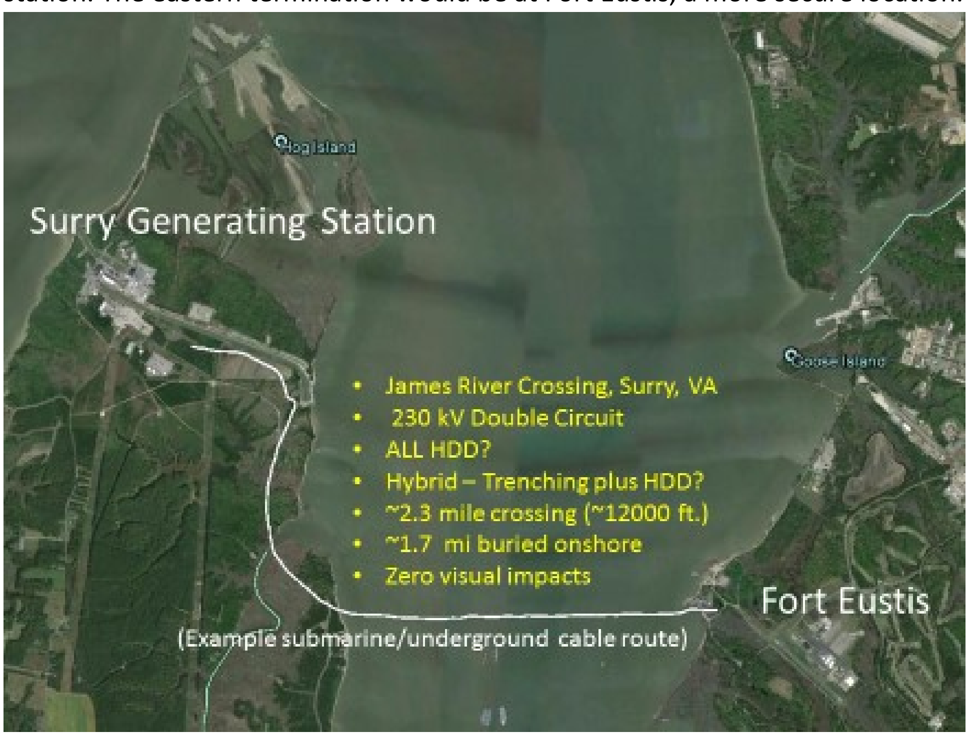

Figure 6- Possible James River Crossing Route for Buried/Submarine System

Reduce Weather Risk Exposure

The only major blackout impacting the peninsula occurred from a failure of the line suspended from towers linking the peninsula to the larger grid, as a result of extreme weather. Across the U.S., extreme weather is causing three to five times more power outages since 2000, as shown in Figure 7. The proposed tower crossing would increase risk exposure to extreme weather events just as these events are becoming more frequent. Submarine cables reduce weather risk to zero.

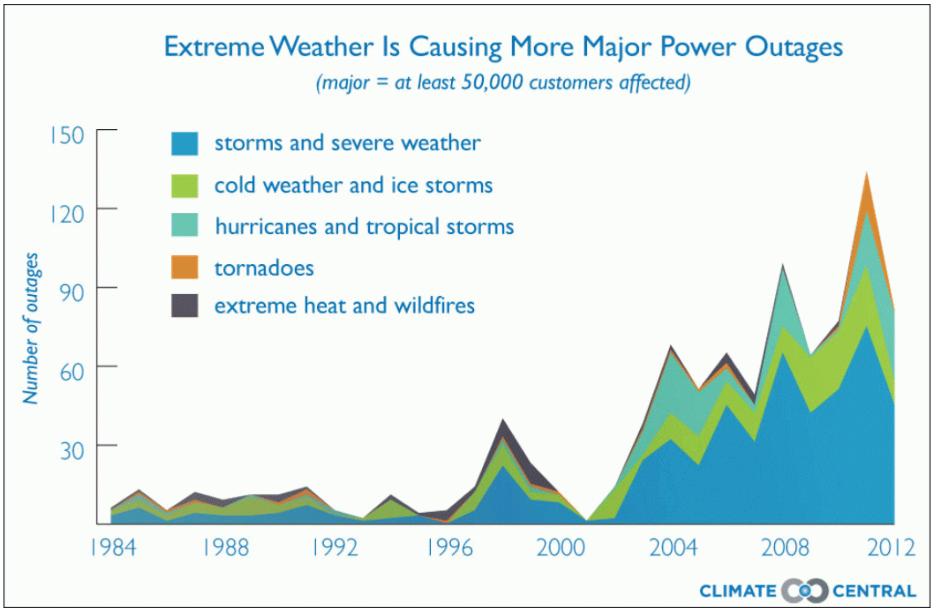

Figure 7- Outages triggered by extreme weather events affecting more than 50,000 customers in U.S., 1984-2012

Avoid Potential for Public Opposition and Litigation

Transmission towers usually generate public opposition, and river crossings even more so. A recent PJM study of five proposals for a similar transmission project crossing the Delaware River recommended a submarine cable plan for its cost certainty, reliability, and lower likelihood of public opposition[7],[8]. Consultants to PJM emphasized that regarding overhead lines, high levels of public opposition should be expected due to impacts to the landscape, aquatic habitats, and shipping concerns. The consultants also concluded that issues associated with view sheds, shipping, fishing, and anchoring would be minimized with a submarine cable installation and proper consultation with USACE, USCG, and others. The report

[7] http://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx

[8] http://www.pjm.com/~/media/committees-groups/committees/teac/20140519/20140519-delmarva-peninsula-lines-constructability-analysis.ashx

also concluded that the use of HDD for crossing sensitive habitat on the shorelines greatly reduced impacts and mitigates concerns related to water quality. HDD technology requires no surface excavation except a small area on the shore to set up the rig and start the borehole. Another related conclusion was that utilizing HDD for the shore crossing is less likely to require a National Environmental Policy Act (NEPA) Environmental Impact Statement (EIS). In spite of the potential permitting issues identified for a submarine crossing, the report stated:

"The temporary disruption of Delaware River habitats as a result of submarine cable installation is preferable to the ongoing permanent disruption caused by overhead transmission river crossings and associated tower structures."[9].

For the reasons cited above, PJM and their consultants and experts selected a plan with a two circuit submarine 230 kV system, citing reduced risk of opposition and the contractor's offer of a hard cap on cost overruns related to on-site factors.

"Surry-230 kV Partial"

DVP considered an alternative developed by LS Power called the "Surry-230 kV Partial" that included a 230 kV submarine link and a Phase Angle Regulator (PAR) for an estimated cost of $99 million. The assumption was that both HDD and plow trenching would be required. No new transformer would be required at Skiffes Creek since the line could tap into the existing 230 kV system. DVP's analysis stated that the 230 kV link would not solve reliability issues since it would result in overloading the 230 kV system on the Surry side of the river under contingency conditions. Other reasons given for dismissing the idea were the time required for implementation and remaining NERC violations related to overload of the 230 kV system on the Surry side of the river. However, to avoid overloading the 230 kV system on the Surry side, the line could be stepped up to join the 500 kV system at Surry. Thus a new transformer would be needed on the Surry side. A load flow analysis would be required to definitively test the system performance and reliability. This alternative has not been considered by DVP.

Impact on Real Estate and Scenic Value

Appendix D includes a letter from the Director of the National Park Service to the Corps, urging denial of the permit for the proposed tower crossing, and outlining the significant impacts the project would have on unique, nationally significant historic and cultural resources.

Land values along the James River also would be negatively impacted by construction of the proposed overhead line. An estimated 80 developed residential properties along the James River that would be in the viewshed of the proposed line crossing. Some or all of the 17 towers in the river could be seen from

[9] The cap did not apply to over-runs related to changes in legislation, policy, capital requirements, etc.

these properties. Many of properties include high value homes in the million dollar range. A comparable number of undeveloped properties are zoned as residential. The value of these properties also would be diminished should the proposed towers be built.

The actual loss in property value depends on the location, regional pricing, land use classification and most important, proximity to the transmission line and scenic value of the property. Of the extensive literature on this subject, none of the identified studies addressed river crossing situations, nor cases with 500 kV transmission lines high in close proximity to high value national historic sites.

The aesthetic impact on visitors to the Colonial National Historic Park and Colonial Parkway would be disruptive throughout the life of the project. In 2014, the economic impact of visitation to Colonial National Historic Park alone was $254 million. The transmission towers would degrade the visitor experience, and thus threaten tourism dollars.

To properly evaluate the impacts a more detailed survey of properties, their owners, and other impacted individuals should be conducted. One technique that is used to quantify damages in litigation is to conduct a Contingent Valuation Survey. The Army Corps of Engineers has ample expertise in this technique. The impacted parties are asked how much extra they would be willing to pay to avoid living with the undesirable situation. In this case, a survey would determine what a property owner or National Park tourist would be willing to pay to not have tall towers in the viewshed. For example, would they pay $1.00 per month extra on their power bill or a nominal surcharge on an entrance fee. This value is then multiplied by the number of land owners and visitors to estimate the condition avoidance value. There are about 80 land owners involved and an average of 3.3 million visitors to the Colonial National Historical Park annually times the life time of the power line. This would be considered a minimum since the permanent value to a national historic site would be much greater.

Summary and Conclusions

Further study and discussions with Dominion Virginia Power and US Army Corps of Engineers have confirmed and reinforced the previous report's findings. Specifically:

1. Dominion overestimated peak load and economic growth projections. The predicted 1.9 percent average annual growth factor used in demand forecasts has not occurred. For the past five years since 2011, demand for power has actually declined across the Dominion service area, especially on the Hampton Peninsula. Three of Dominion's largest local power customers, military bases and an Energy Department laboratory, have collectively decreased their energy usage by 14.8 percent in the last four years. Their goal is a 30 percent reduction by 2025 as established by federal legislation and Presidential Executive Orders. Detailed analysis of plant emission data confirmed that Dominion has been running the Yorktown generating units less each year.

2. Increased use of solar, demand side management (DSM) and energy efficiency improvements could further reduce power demand. Solar photovoltaic systems could add up to 8o MW distributed generation at the point of use, thus reducing demand and eliminating transmission losses. DSM and

efficiency can also be significantly expanded. In combination these changes can reduce the size and capacity of the proposed transmission project by eliminating load growth for at least five years. Extension in December 2015 of federal tax incentives for solar and other renewables assures that their dramatic expansion will continue.

3. Dominion oversized the proposed power line, driving up its cost. The current proposal of a 500 kV line rated at 5000 MVA -- which can carry up to 5000 MW -- is excessive. This is more than four times the total capacity of the Yorktown plant (units 1, 2 and 3 are collectively rated at 1140 MW). This overdesign had its largest impact on submarine cable costs, since in Dominion's study it resulted in an extremely wide right of way and a long cable run.

4. Dominion's evaluation of alternatives and related costs appear outdated and inadequate. After Yorktown plant is decommissioned (currently scheduled for 2020), a transmission project will be needed to insure reliability. The option for using a submarine high voltage transmission cables should be reexamined in light of new cable system designs and installation techniques. In this report nine related underground line projects were reviewed. Costs were found to be significantly less than Dominion's. New horizontal drilling technology can further reduce cost, environmental impacts and disruptions during construction. A submarine cable would avoid major environmental issues and reduce public opposition and impacts on land values in the nearby view shed. In addition overhead lines are vulnerable to terrorists and severe weather.

5. Environmental concerns on a project of this size and sensitivity should be addressed in a full Environmental Impact Statement. In addition to findings described above, there are concerns regarding habitats for birds, spawning grounds for protected species of fish and other fauna and flora. Strong concerns raised by the National Park Service and the interested public call into question the purpose and need for the project as set forth by Dominion, and support a decision by the USACE to require completion of a full Environmental Impact Study to provide further independent analysis.

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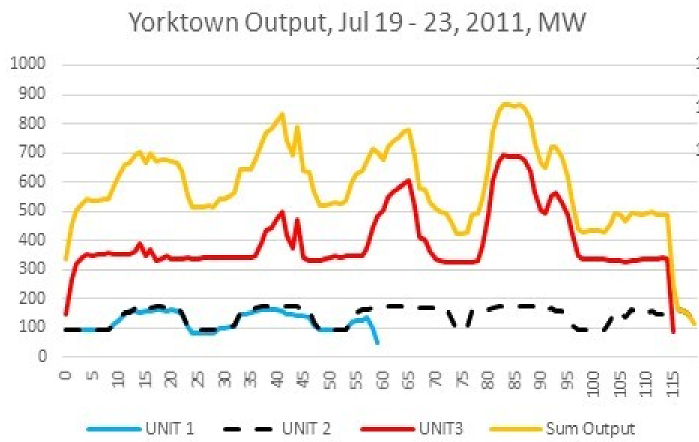
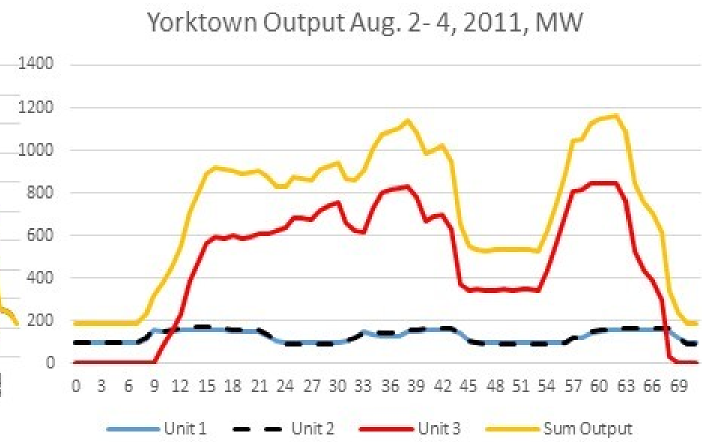
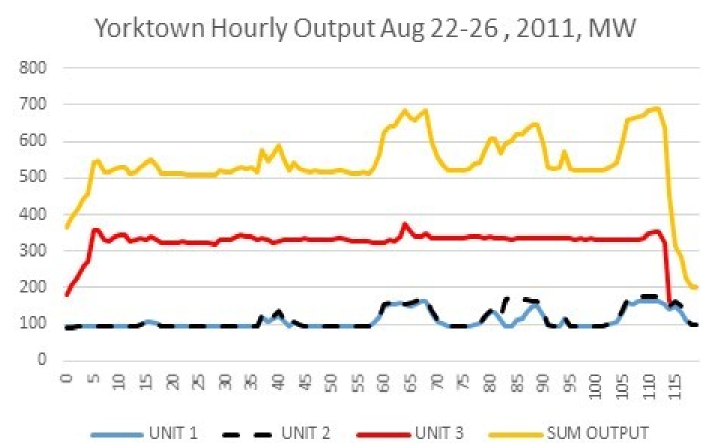
Appendices A through D

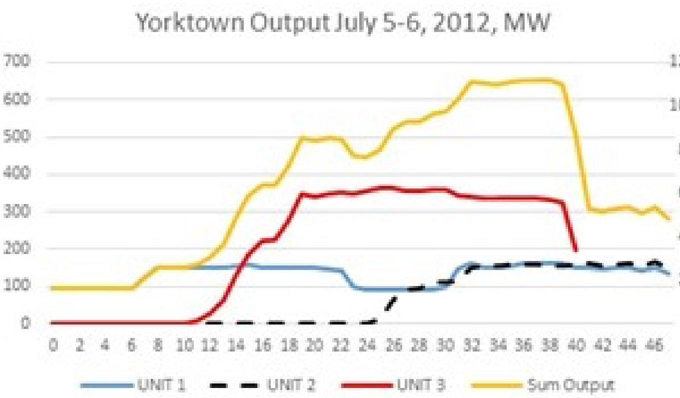
APPENDIX A - YORKTOWN OPERATIONS DURING SUMMER PEAKS

The series below includes graphs of hourly output of Yorktown Generating Station units for all periods during July or August of 2011-2015 when Yorktown units were operating. It is derived from EPA emissions data. First, all periods of Unit 3 operation are graphed, then all periods of Unit 1 and 2 operating separately from Unit 3 are shown. The conclusion is drawn that the full capacity of Yorktown is not needed to meet summer peak demand and that Unit 3 alone has been managing this task since July 2013.

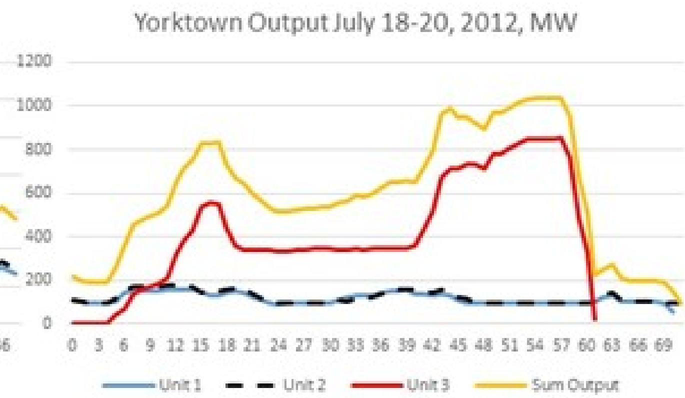

Yorktown Output, Jul 19 - 23, 2011, MW
UNIT 1
UNIT 2
UNIT3
Sum Output


Yorktown Output Aug. 2- 4, 2011, MW
Unit 1
Unit 2
Unit 3
Sum Output

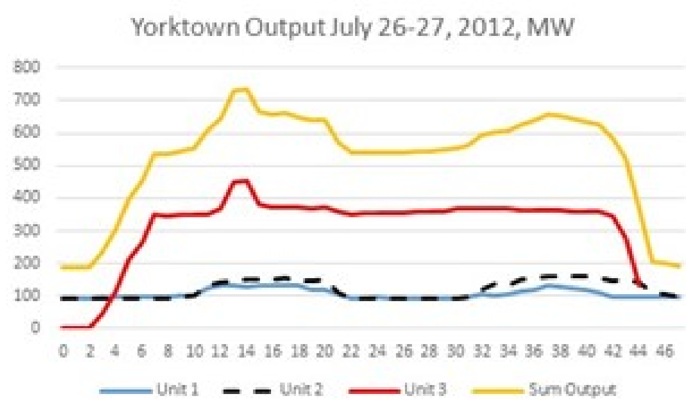

Yorktown Hourly Output Aug 22-26 , 2011, MW
UNIT 1
UNIT 2
UNIT 3
SUM OUTPUT



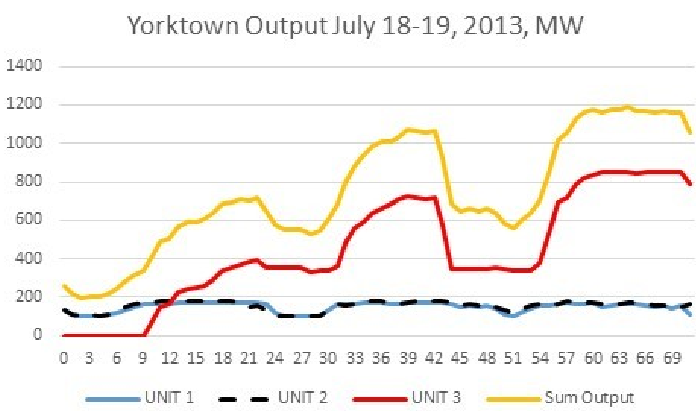
Yorktown Output July 5-6, 2012, MW
UNIT 1
UNIT 2
UNIT 3
Sum Output

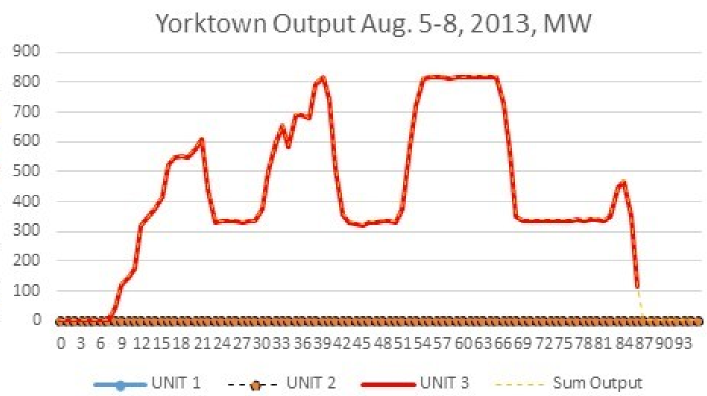


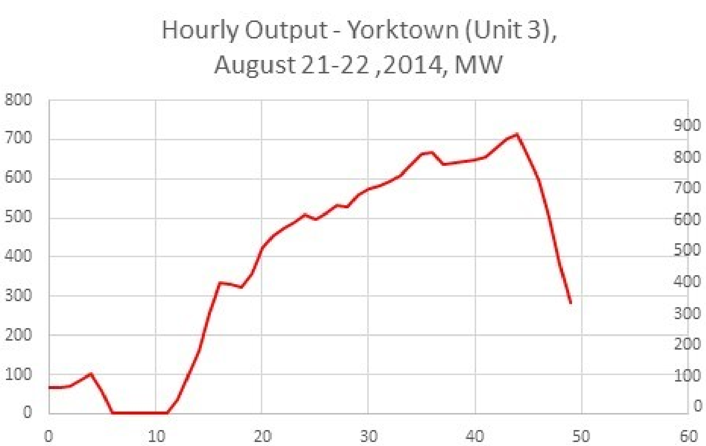
Yorktown Output July 18-20, 2012, MW
Unit 1
Unit 2
Unit 3
Sum Output

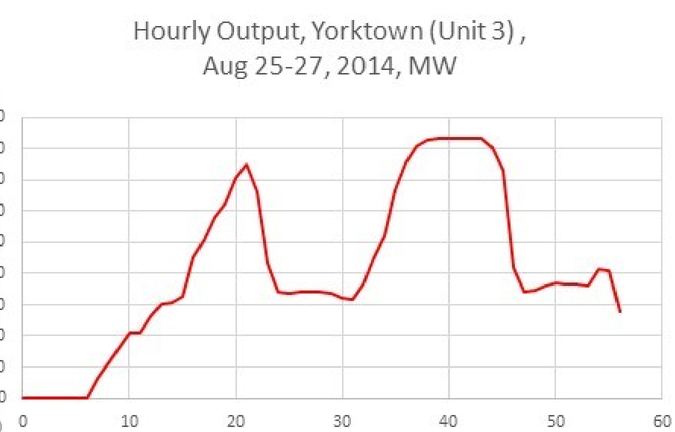


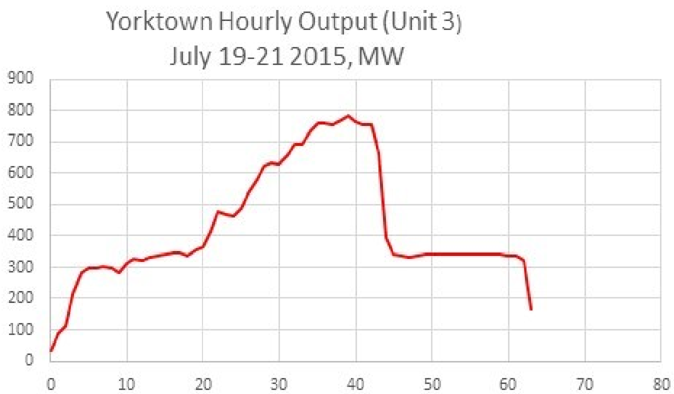
Yorktown Output July 26-27, 2012, MW
Unit 1
Unit 2
Unit 3
Sum Output

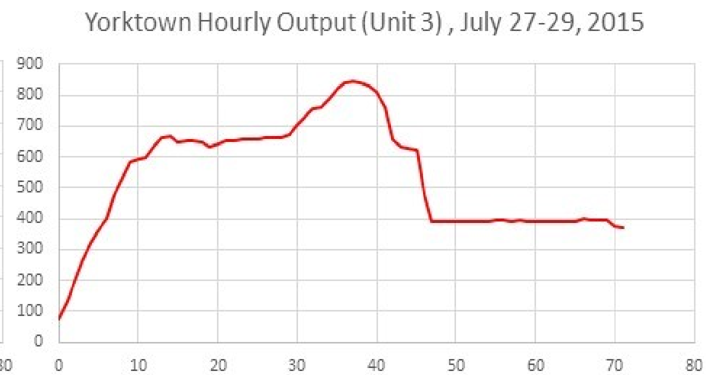

Yorktown Output July 18-19, 2013, MW
UNIT 1
UNIT 2
UNIT 3
Sum Output

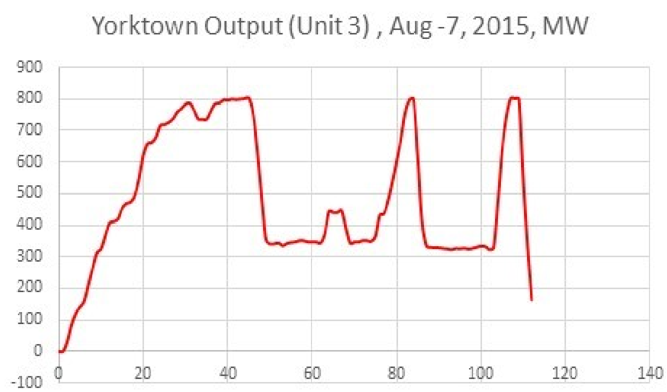

Yorktown Output Aug. 5-8, 2013, MW
UNIT 1
UNIT 2
UNIT 3
Sum Output


Hourly Output - Yorktown (Unit 3),
August 21-22 ,2014, MW

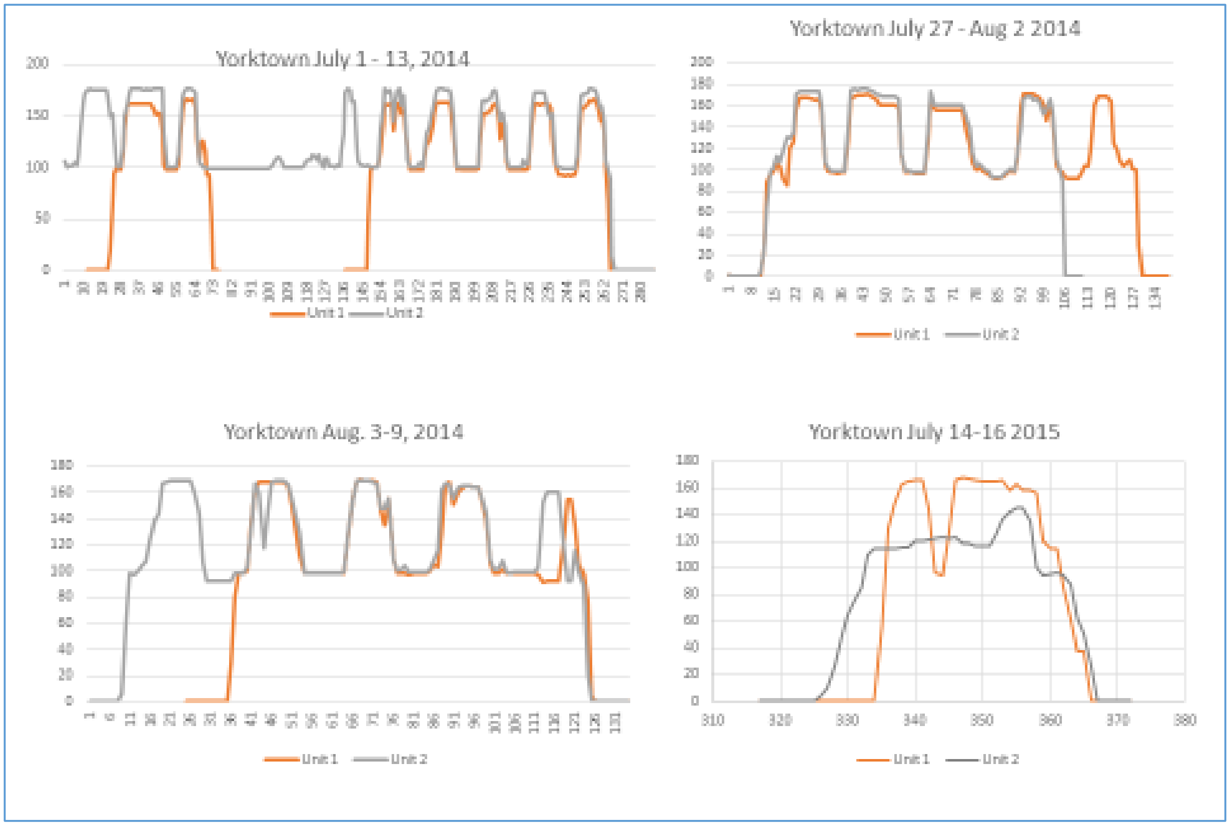

Hourly Output, Yorktown (Unit 3) ,
Aug 25-27, 2014, MW


Yorktown Hourly Output (Unit 3)
July 19-21 2015, MW
900
800
700
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
80


Yorktown Hourly Output (Unit 3) , July 27-29, 2015
900
800
700
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
80


Yorktown Output (Unit 3) , Aug -7, 2015, MW
900
800
700
600
500
400
300
200
100
0
-100
0
20
40
60
80
100
120
140

The graphs below show periods of Unit 1 and 2 operations in July and August, 2014 and 2015. None of the operations occurred within 48 hours of Unit 3 operations.



APPENDIX B-

Background for Understanding System Reliability and Transmission Planning

As a member of PJM, DVP is legally bound to ensure that their system meets reliability standards from the North American Electric Reliability Council (NERC), an industry group that sets standards for long term transmission planning to ensure system reliability.

NERC Methodology for Reliability Studies: Guidelines With Flexibility

NERC Transmission Planning Standards TPL-001, TPL-002 and TPL-003 mandate a minimum level of grid performance under different operating conditions in order to ensure system reliability. Transmission system operators and planners use “load flow” models to simulate these conditions in a digital model of all major grid elements to test the grid’s stability and resilience. Load flow studies are conducted periodically to determine if existing and planned grid infrastructure can manage present and future peak loads and meet NERC reliability standards in the short term (1-5 years) and long term (6-10 years). NERC does not prescribe a standard algorithm or exact methodology, but the analysis must include a scenario assessment and a probabilistic assessment based on hourly load forecasts and/or frequency distribution functions of loads. The main intent and effect of the NERC reliability standards is not to dictate a quantitative margin of reserve generation or transmission capacity for every scenario, but to ensure that individual balancing areas can absorb the loss of one or two elements simultaneously without triggering cascading failures beyond the service area of the failed elements.

The exact methodology and many input assumptions to the reliability assessment are therefore left up to the system operator, allowing considerable leeway in implementation. For example, scheduling of outages in the load flow studies is set by the system operator. This can have a significant effect on grid performance during contingency event simulations and can materially change the load flow study results. Changes in grid conditions outside of NHRLA, including outages in other balancing areas, can also affect loads within NHRLA, since they can shift the flow of power from one 230 kV circuit to another. For example, if a line feeding into South Hampton Roads was down for scheduled maintenance, there would be less power available to NHRLA from the southern link, so more power would have to come from Yorktown or else down the peninsula on the Lanexa line.

In their 2012 testimony to the SCC, Dominion staff testified that “*Dominion’s load flow studies are performed for “critical system conditions”, which means the largest generator in the area is offline. Then the studies assume the loss of different transmission links, one at a time Thus, Y1 is assumed offline. “ (Nedwick testimony vol. II, p. 8-9).*

A major component of the reliability analysis is concerned with peak load studies since they represent the greatest stress on the system. These studies rely on peak load forecast data provided by PJM to each of its members - in this case, peak loads for the DOM zone. DVP then takes these peak loads and allocates them among different load areas within their territory to test system capacity and operational management strategies. NERC guidance discusses the use of either historic hourly data or frequency distribution functions for peak loads, but does not prescribe an exact methodology- again, allowing system operators considerable leeway.

NERC Reliability Assessment Guidebook 2012[10]. - "In thermal systems or those with little energy-limited generation, each day may be considered independent. For the most part, equivalently increasing the number of trials performed increases the number of peak loads that are tested. In the limit, the range of peak loads can be described as a distribution of peak loads. Therefore, uncertainty in daily peak loads can then be reduced to the distribution of daily peaks"–

The Role of "N-1" Studies in Reliability Assessment

To test system performance under different operating conditions, NERC defines 4 different conditions by the number of failed elements[11], and classifies them as Category A through D[12]. Category A is fully operational, Category B covers the loss of one element (usually the principal generator), Category C means the loss of two elements, and Category D is defined as an extreme event resulting in two or more elements removed or cascading out of service.

Categories B and C are also referred to in the industry as "N-1" and "N-1-1" contingencies, respectively, referring to the normal number of generation and transmission elements in the system (N), and the loss of one or more of those elements. For Category B, the loss of a single element (N-1), the system is expected to operate normally, with no load shedding or emergency load management. For Category C, the loss of two elements (N-1-1), the system is still expected to avoid thermal or voltage violations and avoid cascading blackouts, but operators may do so by shedding load in a controlled manner and/or curtailing exports[13]. As a matter of policy, operators plan their systems to avoid voltage and thermal violations *without* loss of load.[14]

Under Category D, NERC does not require evaluation of all possible facility outages listed in Table 1 of the TPL-003 Standard. Normally the transmission planning entity will define a number of extreme, critical contingencies that are listed under Category D and select them for evaluation. The system is not required to avoid loss of load OR cascading shut-downs under a Category D event, but the simulation of these events is included in the standards in order to examine their impact and recovery time.

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[10] http://www.nerc.com/files/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf

[11] "Element" refers to a major generation or transmission asset.

[12] http://www.nerc.com/files/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf

[13] (TPL-003, table 1, footnote c,)

[14] Although it is clearly not desired or proposed by anyone, the point must be made that shedding load under contingency conditions in order to avoid voltage drops, overheating, or cascading outages does not violate NERC reliability criteria, it violates Dominion operational criteria.

APPENDIX C- HVAC Submarine Cable - Summary of Projects

The following points below summarize the key findings from the survey of nine underground and submarine cable projects or cost estimates described in this Appendix.

1. Underground and submarine HVAC cable technology is proven, widely accepted and new techniques and cable designs allow higher capacity submarine systems with sufficient MVA ratings for the James River project.

2. Current FERC standards and military security and reliability requirements favor the use of submarine cable river crossing.

3. Public acceptance outweighs the higher cost. That has been concluded for projects in areas with relatively low scenic, touristic and shoreline land value. Not to mention the added value of a national historic site.

4. Submarine cables can help avoid public opposition and potential costly litigation.

5. DPV's stated estimate of $100 M/mile of submarine cable is excessive, almost three times the industry's estimated cost of $35 M/mile for a single circuit 230 kV line. If two circuits are required, the cost for the pair should be less than $70 M/mile.*

*Note that these are budgetary estimates based on prior projects. Engineered cost estimates could vary depending on soil conditions, archeological obstacles, land cost, site preparation, civil works and permitting issues. This is the case for both submarine and overhead line construction.

Examples of Underground/Submarine HVAC Cables

This section summarizes several recent projects to install buried and submarine cable systems in the 300-500 kV range that have been rated for service up to 4500 MVA. It discusses each project briefly as it relates to the proposed DVP project. Several of these projects utilize horizontal directional drilling (HDD). In this process, a long, flexible boring rig is used to drill a hole underground, and a pipe is pulled through to serve as a conduit. Cable is then pulled through the conduit. There is a limit to the distance that a large cable can be pulled through a conduit. As length increases, so does cable weight, friction, and pulling tension. The cable armor must be built up for the cable to take more pulling tension, but that increases weight and friction and requires ever greater pulling tension. The maximum length is also a function of the maximum burial depth and curvature of the route. For cables in the range of 23 0 kV-50 0 kV, this limit has historically been on the order of 5,000 – 6,000 feet. However using new materials and techniques, installations exceeding 11,000 feet are now in operation. These cases are discussed in the following sections.

The table below provides some basic specs on buried or submarine high voltage cable systems in operation around the world. The discussion following that provides descriptions of many other cable projects that have included river crossings.

In one of the studies discussed below, Artificial Island, the PJM consultant UC-Synergetics (UCS) concluded that, "The overall estimated costs between the five options presented varied substantially between companies and between proposals. The estimated cost range went from a low of $116.3 Million to a high of $269.2 Million. These cost estimates can be compared to Standard Industry Unit Measures shown in the table below. The submarine river crossing options were the most expensive options presented and will be the more difficult options to obtain necessary permits. **However, it is UCS's opinion that the submarine crossing options will provide the most publicly acceptable solutions."**[15]

Underground High Voltage Alternating Current Projects (HVAC)									
Location	**Country**	**Completed/Estimated**	**Underground Technology**	**Voltage (kV)**	**Capacity (MW)**	**Distance (km)**	**Method of Install**	**Supplier/ Consultant**	**Cost**
Omen Lange Gas Field	Norway	2008	4 XLPE	420		3.2 in water depth to 1100 m		Nexans	
Bayonne Energy Center, New York Harbor	USA	2011	3 XLPE with 10 m separation	345	602	10.4 Submarine 1.1 buried	HDD for underground	ABB	
Jutland to Funen	Denmark	2013	3 core cable	420	1100	7.5 Submarine 5.5 buried	pipe in shallow trench	ABB	
SMECO- Holland Cliffs	US, MD	2015	230 kV 3200kcmil XPLE lead sheath	230 x 2		3.2 km, incl 1.4 kmHDD.	HDD to cross river		$21M
Southern Cal Edison - Tehachapi Renewable Transmission Project	USA	anticip. 2016	Single circuit XLPE cable (2 per phase)	500	4500	5.6 underground	trench		
Woodbridge Energy Center	US, NJ	anticip. 2016		230 double	700+	3.35 km HDD +1.5 km	all HDD	CPV, US	
Artificial Island	US, NJ	2017	2500 kcmil XLPE armored submarine (six cables total)	230 x2		4.5 km crossing +1.1 km onshore	HDD plus trench	LS Power	$150M
PEPCO- Potomac Crossing (MAPP)	US, MD	tbd	nine cables	500		3.4	HDD plus trench	Black and Veatch	$90M
James River, Surry, 2012 Estimate from LS Power	US, VA	tbd	XLPE armored submarine	230	1000		HDD plus trench	LS Power	$84M

[15] Allen, Glen N., P.E., *Constructability Analysis of Artificial Island Delmarva Peninsula Project Proposals,* Page 5, UC Synergetics for PJM, April 30, 2014.

Cost Estimates of Industry Standard Unit Measures:

Transmission Components	Dollars	Units	
230kV overhead transmission	$3,500,000	per mile	
230kV underground transmission	$10,500,000	per mile	
230kV submarine transmission	$35,000,000	per mile	
230kV transmission line dead-end structures	$300,000	per unit	
Aerial Delaware river crossing	$100,000,000	per crossing	(Cost supplied by PJM)

* Notes:
- Costs can vary widely based on actual site specific locations, requirements and conditions.
- Cost estimates are budgetary installation costs only based on past projects and experience.
- Factors that may significantly increase these installation costs include:
    - Environmental, Regulatory Licensing Costs
    - Permitting costs
    - Land purchase costs
    - Civil work including site preparation, grading, wetland mitigation, and other encountered conditions
    - Rock excavation.

SMECO – Holland Clff 230 kV Project- HDD Crossing

Southern Maryland Electric Cooperative (SMECO) recently completed a similar project that included the installation of tall towers, a switching station, 20 miles of transmission line and approximately 2 miles of underground transmission cable circuit across the lower Patuxent River in their *"Holland Cliff to Hewitt Road 230 kV Transmission proposal in Calvert and St. Mary's Counties, Maryland"*. The project included construction of a 3.2 km section of 230 kV line crossing the Patuxent River.

An Environmental Assessment (EA) for the project was conducted in 2010 which describes the project's purpose and need, alternatives, and impacts[16]. The EA was triggered by a SMECO application for a federal loan for the proposal. The Rural Utilities Service (RUS) of the U.S. Department of Agriculture was the lead agency on the EA since the project utilized the RUS loan program. The EA was prepared pursuant to the National Environmental Policy Act of 1969 (NEPA) (U.S.C. 4231 et seq.) and in accordance with the Council on Environmental Quality's (CEQ's) regulations for implementing the procedural provisions of NEPA (40 CFR parts 1500-1508) and RUS's NEPA implementing regulations (7 CFR part 1794, Environmental Policies and Procedures).

The land-based portion of the route was installed conventionally in a concrete-encased duct bank, and the Patuxent River crossing portion of the route was installed via two parallel Horizontal Directional Drills (HDDs), with the second HDD conduit bank intended for a future additional circuit. The HDD line was installed below the Patuxent River bed for a lateral distance of about 4600 feet. The EA stated (in 2010) that this was the maximum distance that an un-armored cable can be pulled through conduit with

[16] http://www.rd.usda.gov/files/UWP_MD04-SMECO_HollandCliffs_EA.pdf

the depths and slopes required for the crossing. The Patuxent is 110 feet deep at the crossing and the burial depth was an additional 50 feet, which greatly reduced the maximum pull length. An alternative crossing site that would have required about 5,600 feet of HDD was not selected because it would have required steel conduit and armored cables to withstand the higher pulling tension, and more circuits to compensate for lower line capacity, which significantly increased the cost.

The 3.2 km circuit utilizes 23 0 kV 3200kcmil XPLE lead sheath cable[17]. The installation of a 1.4 km length of cable under the Patuxent River represents a major advancement for buried and submarine solid dielectric cable installations. Cable reel weights (138,900 lbs.) and sizes (13’4” tall x 18’ wide) presented challenges that were successfully overcome. The cost of the river crossing section (1.4 km HDD + 1.8 km trench burial) was projected to be $21.6 million.

In 2010, the RUS issued a Finding of No Significant Impact (FONSI)[18] for the Environmental Assessment (EA), citing a lack of significant impacts, including visual impacts.

[17] http://www.newriverelectrical.com/services/underground-high-voltage-transmission/
[18] https://www.gpo.gov/fdsys/pkg/FR-2010-10-22/html/2010-26747.htm

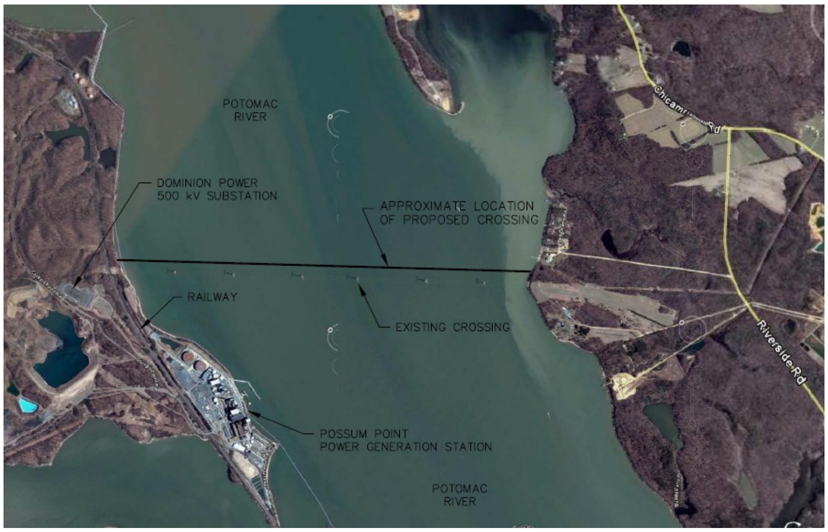
Owner	SMECO			Computed By	J. Bardwell
Project	Southern Maryland 230kV Reliability Project, Patuxent River Crossing			Date	25-Aug-08
B&V File No.	146026.53.0000			Checked By	
Title	River Crossing, Center Route			Date	
Estimate Overall Route Length	1.97 Miles			1 Circuits	
	10402 Feet	4 Splices per Circuit		1 Cables per Phase	

Item	Qty	Unit	Material Unit Cost	Total Mat'l Cost	Labor Unit Cost	Total Labor Cost	TOTAL COST
CABLE SYSTEM FURNISH AND INSTALL							
UG CABLE AND ACCESSORIES SUBTOTAL				$6,795,120		$1,079,400	$7,874,520
Cable cost per route foot (1 Circuit)	$630.00 (Does not include Accessories)						
COMMUNICATIONS							
CABLE SYSTEM COMMUNICATIONS (FO) SUBTOTAL				$71,310		$91,731	$163,040
DISTRIBUTED TEMPERATURE SENSING SYSTEM							
DTS SUBTOTAL				$0		$0	$0
CIVIL WORK							
GENERAL SUBTOTAL				$0		$224,625	$224,625
STRUCTURES SUBTOTAL				$144,855		$175,914	$320,769
SPLICING VAULT SUBTOTAL				$248,000		$180,800	$428,800
DUCTBANK INSTALLATION				$1,833,017		$2,937,655	$4,770,672
Ductbank cost per route foot (2 Circuits)	$808.37						
HDD INSTALLATION SUBTOTAL				$1,350,000		$3,393,000	$4,743,000
HDD Ductbank cost per route foot (2 Ckts)	$1,054.00						
JACK AND BORE SUBTOTAL				$0		$0	$0
ESTIMATED LABOR & MATERIAL COST				$10,442,302		$8,083,125	$18,525,427
ESCALATION (Not Included)	0 Years @		10.00%	$0		$0	$0
ESCALATED CONSTRUCTION COST				$10,442,302		$8,083,125	$18,525,427
CONTINGENCY/MISCELLANEOUS	10.0%	of Est. Labor & Mat.		$1,044,000		$808,000	$1,852,000
ESTIMATED PROJ COST				$11,486,302		$8,891,125	$20,377,427
STATE SALES TAX	0.0% of Materials			$0			$0
TOPOGRAPHIC SURVEYING/SOIL EXPLORATION @ $25,000/mi							$49,250
ENGINEERING AND CONSTRUCTION SUPPORT							$675,000
CONSTRUCTION MANAGEMENT							$450,000
ESTIMATED TOTAL PROJ COST							$21,551,677

PEPCO/MAPP Potomac River Crossing – 500 kV Hybrid Crossing (HDD and Plow)

In 2008, as part of the Mid Atlantic Pathway Project (MAPP), PEPCO hired Black and Veatch to look at a 500 kV, submarine cable crossing of the Potomac River. The Potomac River is approximately 10,500 feet wide and 32 feet deep at the crossing point. They considered several different cable types and configurations that included both trenching across the river bottom and HDD to cross both banks. For this hybrid method of installation, HDD is used to drill from dry land, beneath the riverbank, and into a coffer dam in shallow water. First conduit, then the cable is pulled through the HDD hole. A barge or cable vessel then tows a mechanical (or jet) plow slowly across the river as cable is laid into a trench. The cable is then pulled through the HDD conduit similarly on the opposite shore.

Black and Veatch's estimate for the river crossing was $90 million, using three cable per phase (nine total), for a distance of about 11,200 feet. This included the HDD work, the trench/plow work, and transition/connection stations at each end of the cable. The transition station cost includes the cable terminations, surge arrestors, any relaying or monitoring equipment required and a large frame structure to jumper the terminators to the overhead conductors. This is very close to the length of a James River crossing that would land at Ft. Eustis (~12,000 feet). Although this estimate was in 2008 dollars, it is valid for rough comparison purposes.



Owner	Pepco Holdings Incorporated	Computed By	J. Bardwell
Project	Mid Atlantic Power Pathway	Date	21-Oct-08
B&V File No.	161518.26.0200	Checked By	
Title	Potomac River, Submarine Cable Crossing Estimate, XLPE	Date	
Estimate Overall Route Length	2.12 Miles	1 Circuits	
	11200 Feet — 0 Splices per Circuit	3 Cables per Phase	

Item	Qty	Unit	Material Unit Cost	Total Mat'l Cost	Labor Unit Cost	Total Labor Cost	TOTAL COST
CABLE SYSTEM FURNISH AND INSTALL							
UG CABLE AND ACCESSORIES SUBTOTAL				$38,760,748		$37,604,513	$76,365,261
Cable cost per route foot (3 Cables per Phase)	$6,444.00 (Does not include Accessories)						
COMMUNICATIONS							
CABLE SYSTEM COMMUNICATIONS (FO) SUBTOTAL				$80,600		$100,180	$180,779
DISTRIBUTED TEMPERATURE SENSING SYSTEM							
DTS SUBTOTAL				$0		$0	$0
CIVIL WORK							
GENERAL SUBTOTAL				$0		$101,515	$101,515
STRUCTURES SUBTOTAL				$371,468		$595,320	$966,788
TRENCHING FOR DIRECT BURIAL				$20,392		$80,048	$100,440
Trenching cost per route foot	$251.10						
HDD INSTALLATION SUBTOTAL				$432,000		$1,998,000	$2,430,000
HDD Ductbank cost per route foot	$4,050.00						
ESTIMATED LABOR & MATERIAL COST				$39,665,208		$40,479,576	$80,144,784
ESCALATION (Not Included)	0 Years @		10.00%	$0		$0	$0
ESCALATED CONSTRUCTION COST				$39,665,208		$40,479,576	$80,144,784
CONTINGENCY/MISCELLANEOUS	10.0%	of Est. Labor & Mat.		$3,967,000		$4,048,000	$8,015,000
ESTIMATED PROJ COST				$43,632,208		$44,527,576	$88,159,784
STATE SALES TAX	0.0%	of Materials		$0			$0
MARINE SURVEYING/SEDIMENT TESTING							$137,878
ENGINEERING AND CONSTRUCTION SUPPORT							$1,100,000
CONSTRUCTION MANAGEMENT							$840,000
ESTIMATED TOTAL PROJ COST							$90,237,662
UNDERGROUND PROJECT TOTAL						(rounded)	$90,200,000

LINK TO FINAL ENGINEERING STUDY OF POTOMAC CROSSING-
https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=5&cad=rja&uact=8&ved=0ahUKEwj7xZHv4LHKAhVLXBoKHXpKCmIQFgg0MAQ&url=http%3A%2F%2Fwebapp.psc.state.md.us%2Fintranet%2FMaillog%2Fcontent.cfm%3Ffilepath%3DC%3A%255CCasenum%255CAdmin%2520Filings%255C110000-159999%255C115300%255CAppendix%2520L%2520-%2520Engineering%2520Study%255CFINAL_%2520Potomac%2520River%2520Crossing%2520Engineering%2520Study%2520-%252002-18-09.pdf&usg=AFQjCNEUsnW2DxWVPJyMx-cVfmfj3UZ3jQ

Artificial Island, NJ - Delaware River Crossing – HDD and Plow

IN 2014, PJM published a constructability analysis[19] of five different proposals for resolving system reliability and stability issues associated with a nuclear facility on the Delaware River. Most of the proposals included a high voltage cable system crossing the Delaware River that would strengthen the link between NJ and DPL territory. In 2015, the alternatives were refined and analyzed and PJM published a white paper presenting the findings[20].

The white paper presents the results of a process that assembled a team of expert consultants and looked at 26 proposals to solve grid operational issues related to efficient operation of the nuclear plant at Artificial Island, NJ. Five finalists were selected and two of the plans used submarine crossings.

The recommended plan is listed in the table below as LS Power 5A. The total crossing length of the submarine cable including HDD sections across both riparian shorelines is more than 3.5 miles, and the river itself is about 2.8 miles wide at the crossing. The submarine cable design consists of two (2) 230 kV 2500 kcmil XLPE armored submarine cables per phase (six cables total) that are jet plowed into the river bed. The design calls for one conductor per trench spaced between 20' to 60' apart (one to two times the water depth) in order to facilitate installation, maintenance, recovery and repair. The net result is a cable ROW that is 440' wide at the deepest point of the crossing. The maximum depth of the river in the area of the proposed route is approximately 45 feet.

The submarine cable plans was recommended by PJM for its cost, reliability, and lower likelihood of public opposition. PJM consultants emphasized that high levels of public opposition should be expected on overhead lines, which are generated by impacts to the landscape, aquatic habitats, and shipping concerns. They also concluded that issues associated with view sheds, shipping, fishing, and anchoring would be minimized with a submarine cable installation and proper consultation with USACE, USCG, etc. The report also concluded that the use of HDD for crossing sensitive habitat on the shorelines greatly reduced impacts and mitigates concerns related to water quality. HDD technology requires no surface excavation except a small area on the shore to set up the rig and start the borehole.

Another very salient and relevant conclusion was that utilizing HDD for the shore crossing is less likely to require a National Environmental Policy Act (NEPA) Environmental Impact Statement (EIS). In spite of the potential permitting issues identified for a submarine crossing, consultants concluded that "*the temporary disruption of Delaware River habitats as a result of submarine cable installation is preferable to the ongoing permanent disruption caused by overhead transmission river crossings and associated tower structures.*"

For the reasons cited above, in their 2015 recommendations, PJM and their consultants and experts selected the LS Power plan with a two circuit submarine 230 kVsystem.

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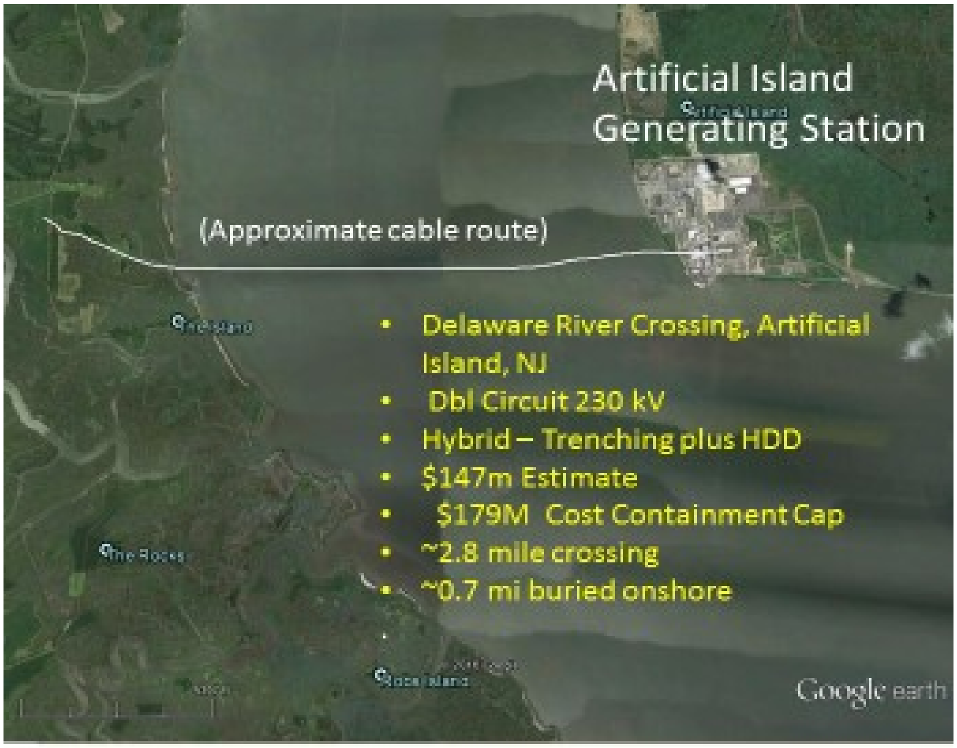
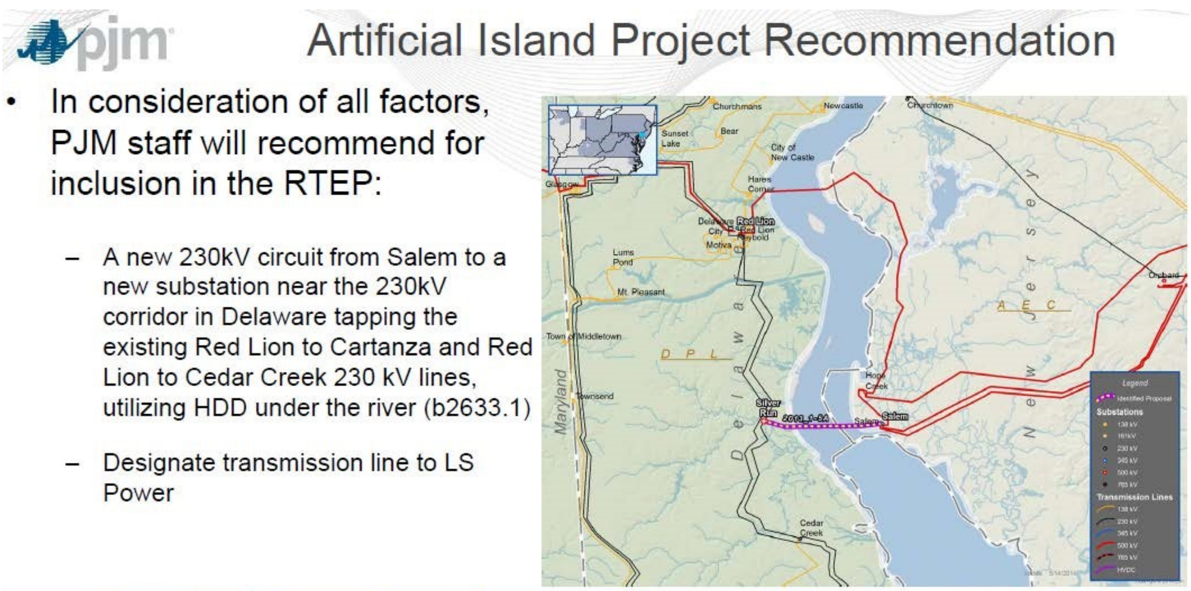
[19] http://www.pjm.com/~/media/committees-groups/committees/teac/20140519/20140519-delmarva-peninsula-lines-constructability-analysis.ashx
[20] http://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx

Costs for this component were estimated in 2015 to be about $146 million. An additional $130-150 million was estimated for power conditioning equipment, substation upgrades and associated equipment, for a total project cost of $276-$296 million. Construction methods include use of swamp mats and 15 helicopter installation operations in wetlands areas. Oceangoing vessels regularly transit the Delaware River at this stage, so cable burial depth of 25 feet was required by the Army Corps of Engineers. Burial depth would likely be lower at the proposed James River crossing, where the largest vessels are river barge tug boats, and there is no risk of snagging the cable with an oceanic vessel–sized anchor.

	Dominion 1C Hope Creek - Red Lion 500 kV Line ($M)	Transource 2B 230 kV Submarine Line ($M)	LS Power 5A 230 kV Submarine Line ($M)	PSE&G Hope Creek - Red Lion 500 kV Line ($M)
Cost Containment (Per Supplemental Proposals)	n/a	$203 - $259	$146	$221
Project Cost Estimate (Where Not Provided)	$211 - $257	n/a	n/a	n/a
Additional Proposal Elements:				
· New Salem Substation	n/a	$41	n/a	n/a
· Existing Salem Substation Expansion	n/a	$14 - $17	$61 - $74	n/a
· Existing Red Lion Substation Expansion	n/a	n/a	n/a	$4 - $6
OPGW / GSU Taps	$20	$25	$25	$20
SVC Cost Estimate	$31 - $38	$31 - $38	$31 - $38	$31 - $38
Project Capital Cost Total Estimate *Current Year Dollars*	**$263 - $316**	**$313 - $380**	**$263 - $283**	**$277 - $285**
Project Capital Cost Total Estimate *Future Year Dollars*	**$284 - $341**	**$346 - $411**	**$284 - $306**	**$281 - $290**





From http://2.bp.blogspot.com/-wgujU9YFy_Y/Vb9V8AEldPI/AAAAAAAAZl8/43mCGKA0syQ/s1600/PJM_ArtificialIslandProjectRecommendation.jpg

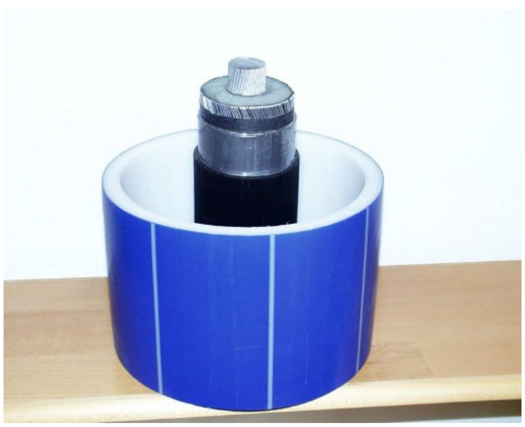
PV Woodbridge Energy Center, Woodbridge, NJ – HDD only

In this project, six fused PVC casings 30” in diameter with a total length of 11,000’ were installed by HDD to transmit power from the nearby 700 MW Woodbridge Energy Center in New Jersey[21]. The total section length was 3 miles, including wetlands and a river crossing that could not accommodate a traditional above ground installation. Each of the six casings (the longest being 2600’) held 4—8” conduits - 3 for the cables with a spare totaling 44,000’, 2—2” conduits (for grounding and fiber optic), and a 3” sacrificial thermal grout placement tube. A spacer system held the conduit and tubes in the required spacing for each crossing.

The length of the HDD installation was made possible by using a new design of fused PVC pipe that can be pulled at greater tension, does not reduce cable ampacity (as steel pipes do), and has lower inner wall friction for pulling cables through with much less tension. Specially developed lubricants were used to reduce the friction between the cable jacket and the inner conduit wall. This project opens the distinct possibility that HDD could be used for the entire crossing of the James River, which has the potential to cut the cost by more than half compared to the hybrid submarine installation.

Aalborg DK buried cables 400 kV – Water Filled Conduit

In 2005, a 400 kV cable connection was installed across the Mariager Fjord, on a 2.5 km long section east of the town Hobro. The cables were be pulled through strong, water-filled plastic pipes, previously laid on the bottom of the fjord from a ship. Each of the cables was pulled through its own pipe laying in the riverbed sediment (6 M separation between circuits – 3 conductors/circuit).



[21] From http://www.undergroundsolutions.com/papers/WM-T4-02.pdf

Appendix D - National Park Service Letter

United States Department of the Interior

NATIONAL PARK SERVICE
1849 C Street, N.W.
Washington, D.C. 20240

Office of the Director

DEC 1 1 2015

Lieutenant General Thomas P. Bostick
US Army Chief of Engineers and Commanding General
US Army Corps of Engineers
441 G Street NW
Washington, DC 20314-1000

Dear General Bostick:

The National Park Service would like to convey our serious concerns about the impacts of the proposed Dominion Surry-Skiffes Creek-Whealton Transmission Line project. This project would seriously impact irreplaceable, nationally significant resources.. Running power lines through the landscape where the earliest days of American history were written will forever change the ability of Americans to experience and understand our nation's earliest days.

The proposed overhead line would mar the historic setting that represents the very beginnings of and the military defense of our nation. It would be a massive and modern industrial intrusion in a landscape that retains the feeling and appearance of long ago. It would cross directly over the open water route of the Captain John Smith Chesapeake National Historic Trail. It would be within sight of Jamestown Island and the Colonial Parkway. It would set a precedent for additional development and cumulative effects. It would forever degrade, damage, and destroy the historic setting of these iconic resources. This is not acceptable for resources designated by Congress to ensure their permanent protection.

The National Park Service (NPS) has been communicating with the USACE Norfolk District for more than two years regarding this proposal. Regional Director Mike Caldwell of the National Park Service Northeast Region has spoken with Norfolk District Commander Colonel Jason Kelly. Regional and park staffs have met and communicated regularly with Norfolk District staff. We appreciate the USACE's continuing consultation with us. Throughout these consultations, the NPS has been consistently clear in communicating our high level of concern about the impacts of this proposal.

Last week NPS staff met with the USACE Chief of the Regulatory Branch for the Norfolk District and Project Manager for the current Dominion proposal. They informed the NPS that Dominion intends to submit a plan later this week that outlines Dominion's proposal to mitigate the adverse effects of the company's preferred alternative to build an overhead line across the James River within view of Jamestown Island.

The November 23, 2015, Presidential Memorandum on Mitigating Impacts on Natural Resources from Development notes that, "When a resource's value is determined to be irreplaceable, the preferred means of achieving [the mitigation goal] is through avoidance, consistent with applicable legal authorities."

The project would cause severe and unacceptable damage to this historically important area and the irreplaceable and iconic national resources within it. As stated in the President's memorandum the choice here is avoidance, not mitigation.

While the proposed towers and overhead line would have significant impacts on many historic resources, Jamestown Island, Colonial National Historical Park, and the Captain John Smith Chesapeake National Historic Trail are national treasures that represent the very beginnings of this nation. These treasures were specifically designated by Congress to allow the American people to forever learn and experience our national story through places preserved in perpetuity.

We know from decades of experience protecting and managing nationally significant historic resources such as the John Smith Chesapeake Trail, Jamestown Island, and the Colonial Parkway that people value and understand their history and heritage through experiencing it in place. The historic setting of these resources is integral to being able to understand each and their connection to each other. It is a setting that has survived intact for over 400 years and the reasons presented by the utility company should not compel you to permanently mar this national resource.

The NPS is working with state and local organizations to get the Jamestown Island placed as a significant site on the list maintained by United Nations Educational, Scientific, and Cultural Organization (UNESCO). This is the first step to designation as a World Heritage Site. This project will jeopardize those efforts, eliminating the potential for the Commonwealth of Virginia to claim the home to a World Heritage site and attract millions of visitors from around the world.

The NPS has not participated in discussions regarding mitigation because the Section 106 Assessment of Effects has not been sufficiently completed, nor has the Army Corps' NEPA compliance considered other viable alternatives. We understand the USACE has determined the proposal would have an adverse effect to historic resources in the area, but repeat that the specific effects have not been fully clarified and the severity of those effects has not yet been identified or agreed on. The severity of the Dominion overhead line proposal in such an iconic landscape requires thorough and complete assessment. Once that assessment has been sufficiently completed we believe the sheer magnitude of irreversible impacts will be clear and point to one conclusion: an overhead power line proposal is unsuitable in this location. No amount of mitigation could possibly counteract the severity of the effects that would be caused by this proposal. We urge the USACE to deny the permit for the proposed overhead line and to encourage Dominion Virginia Power to further examine the many other solutions available through an Environmental Impact Statement.

On the eve of the centennial of the NPS, this proposal has become one of the most serious threats to our nationally significant historic resources. This nation has only one Jamestown.

Thank you for your continued serious attention on this matter.

Sincerely,

Jonathan B. Jarvis
Jonathan B. Jarvis
Director

cc: Major General Donald E. Jackson, Jr., US Army Corps of Engineers
cc: Assistant Secretary JoEllen Darcy, Department of Defense
cc: Molly Ward, Secretary of Natural Resources, Commonwealth of Virginia