Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line

In the forthcoming Environmental Impact Statement, the Army Corps should evaluate modular battery storage as a new supply option, and update load forecasts

Prepared for National Parks Conservation Association

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GLOSSARY

- **Chesapeake Energy Center** – A coal-fired power station located in the City of Chesapeake in the SHRLA. The station had four coal-fired steam units with a total nameplate capacity of 649.5 MW and four small gas turbines with a total nameplate capacity of 67.4 MW. Dominion retired the four coal units in December 2014.
- **Coincident peak demand** - Demand from a particular user or sub-region at the time that the large region, in this case the NHRLA, is experiencing peak demand. This is in contrast with non-coincident peak demand, which refers to the peak demand of a specific end-user or region.
- **Contingency conditions / situations** – A contingency condition, in the context of reliability, is a situation whereby one or more generator or transmission resources is unavailable. There are various requirements, set by NERC, for the level of reliability that the system should maintain under different contingency scenarios.
- **Dominion Energy** – The parent company of Virginia Electric and Power Company, the utility that provides electricity to customers in Virginia.
- **Dominion Zone** – The geographic region within PJM's jurisdiction in which Dominion provides electrical service; this includes most of Virginia, including the NHRLA, and part of eastern North Carolina.
- **EIS** (Environmental Impact Statement) – An official document required by the 1969 National Environmental Policy Act (NEPA) for certain actions "significantly" affecting the quality of the human environment.[1] The tool is used to inform decision-making processes.
- **FERC** (Federal Energy Regulatory Commission) – the federal agency that regulates, among other things, the transmission and wholesale sale of electricity and natural gas in interstate commerce.
- **Firm peak capacity -** The amount of electricity available for production which can be guaranteed available during system peak. Resources with firm peak capacity can be reliably turned on (or "dispatched") up to their full capacity in order to meet load.
- **IRP** (Integrated Resource Plan) – A mid-to-long-term resource planning document. Dominion is required to submit an IRP to the SCC on an annual basis.
- **Nameplate capacity** - The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer.
- **NERC** (North American Electric Reliability Corporation) - a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.
- **NHRLA** (North Hampton Roads Load Area) – A geographic area that includes approximately 285,000 electric utility customers across jurisdictions on the Peninsula (counties of Charles City, James City and York, and the cities of Williamsburg, Yorktown, Newport News, Poquoson, and Hampton), Middle Peninsula (counties of Essex, King William, King and Queen, Middlesex,

[1] CEQ NEPA Regulations 40 C.F.R. § 1508.27.

Mathews, Gloucester, and City of West Point), and Northern Neck (counties of King George, Westmoreland, Northumberland, Richmond and Lancaster, and the City of Colonial Beach).

- **NPCA** (National Parks Conservation Association) – Headquartered in Washington DC, with 27 locations and more than 1.4 million members and supporters nationwide, this nonpartisan, nonprofit organization focuses on protecting America's national parks. NPCA works through its program and policy experts, committed volunteers, staff lobbyists, community organizers, and communication specialists to inform and inspire the public and to influence decision-makers to protect our national parks. This report was prepared on behalf of NPCA.
- **PJM** (PJM Interconnection LLC, acronym based upon "Pennsylvania, Jersey, and Maryland") – a regional transmission organization that is responsible for coordinating the movement of electricity in all or parts of 13 states, including Virginia, and the District of Columbia.
- **The Project** – the Surry-Skiffes Creek-Whealton project, which has three components: the Surry-Skiffes Creek 500 kV transmission line, the Skiffes Creek-Whealton 230 kV transmission line, and the Skiffes Creek 500-230-115 kV switching station.
- **SCC** (Virginia State Corporation Commission) – the utility commission for the state of Virginia, responsible for regulating utilities, insurance, state-chartered financial institutions, securities, retail franchising, and railroads.
- **SHRLA** (South Hampton Roads Load Area) – Includes in Virginia the counties of Southampton and Isle of Wight; the cities of Suffolk, Chesapeake, Virginia Beach, Portsmouth and Norfolk; and in North Carolina the counties of Camden, Gates, Currituck, Pasquotank, and Perquimans.
- **Stantec** (The firm of Stantec Consulting) - Dominion retained Stantec to evaluate alternatives to the Project for the U.S. Army Corps of Engineers.
- **Tabors** (The firm of Tabors Caramanis Rudkevich) - The National Trust for Historic Preservation retained Tabors to identify alternatives to the Project that would not require an overhead crossing of the James River and would meet all relevant planning and reliability criteria.
- **U.S. Army Corps (United States Army Corps of Engineers/USACE) –** A federal agency under the Department of Defense that oversees a wide range of public works projects. The U.S. Army Corps is involved in the Surry-Skiffes project because the "Transmission lines will cross several Section 10 waterways, in addition to structures being built in the James River, as well as structural discharges occurring in non-tidal wetlands regulated under Section 404 of the Clean Water Act. The activities required a Corps permit pursuant to Section 10 of the Rivers and Harbor Act and Section 404 of the Clean Water Act regulations."[2]
- **Virginia Electric and Power Company -** The subsidiary utility of Dominion Energy that provides electric service to customers in the state of Virginia.
- **Weather normalization -** The process of adjusting energy or peak load to what would have happened under normal weather conditions. Weather-normalized loads are useful for capturing long-term trends in load growth. The methodology that PJM uses for weather normalization relies on statistical regressions and is constantly evolving.

[2] US Army Corps of Engineers Norfolk District Website Website. *Dominion Power Surry-Skiffes Creek-Whealton EIS.* Published August 6, 2019. Available at https://www.nao.usace.army.mil/Missions/Regulatory/SkiffesCreekPowerLine.aspx.

- **Yorktown Generating Station** – A three-unit power station located in York County on the Peninsula of the NHRLA. The station has two coal-fired units (Units 1 and 2) with a total nameplate capacity of 375 MW and one oil-fired peaking unit (Unit 3) with a nameplate capacity of 882 MW. Dominion retired Units 1 and 2 in December 2019. Unit 3 is limited to operate at only 8 percent annually of its max due to air quality restrictions.

EXECUTIVE SUMMARY

Much has changed since Dominion filed its 2012 application to construct the Surry-Skiffes Creek-Whealton project to meet the electric power needs in the North Hampton Roads Load Area (NHRLA)[1] of Virginia. In July 2018, the Virginia legislature passed the Grid Transformation and Security Act,[2] which mandates significant levels of energy efficiency investment by Dominion. Then, in April of 2020, the Clean Economy Act,[3] which mandates substantially increased levels of solar photovoltaics (PV) and energy storage in Virginia, became law.[4] These cost-effective resource options—mainly battery storage, solar PV, and energy efficiency—coupled with the region's extensive network of 230 kV and 115 kV bulk power lines feeding electricity from the northwest and southern portions of Virginia's Lower Peninsula (Peninsula), are exactly what's required to support and supplement reliable electric power delivery to the NHRLA without relying on Dominion's preferred Surry-Skiffes Creek-Whealton project.[5]

In this report, we review Dominion and the U.S. Army Corps of Engineers' justification for the Surry-Skiffes Creek-Whealton project, evaluate the actual level of need in the NHRLA, and develop a set of alternative portfolios that can meet area need and comply with North American Electric Reliability Corporation (NERC)[6] requirements without the Surry-Skiffes Creek project.

Key findings

1. Dominion's assertion that the Surry-Skiffes Creek-Whealton project is needed to maintain electric reliability in the NHRLA is not supported by the record.
2. Dominion has systematically over-projected demand to justify building the Project, and its territory may have a capacity surplus even without the Project.
3. Dominion's alternatives analysis failed to consider locally sited battery storage, renewables, and demand-side management.
4. The region's existing transmission network would reliably meet the needs of the NHRLA without Dominion's preferred Surry-Skiffes Creek project if combined with alternative resources. Specifically, these resources include locally sited solar PV, continued improvements in available, cost-effective peak-load reducing efficiency measures, and—crucially—highly responsive, predictably dispatchable battery storage resources that also provide critical ancillary services.[7]

Report Recommendations:

1. The forthcoming Environmental Impact Statement (EIS) process led by the Army Corps of Engineers (Army Corps) should directly evaluate the purpose of and need for the Project.

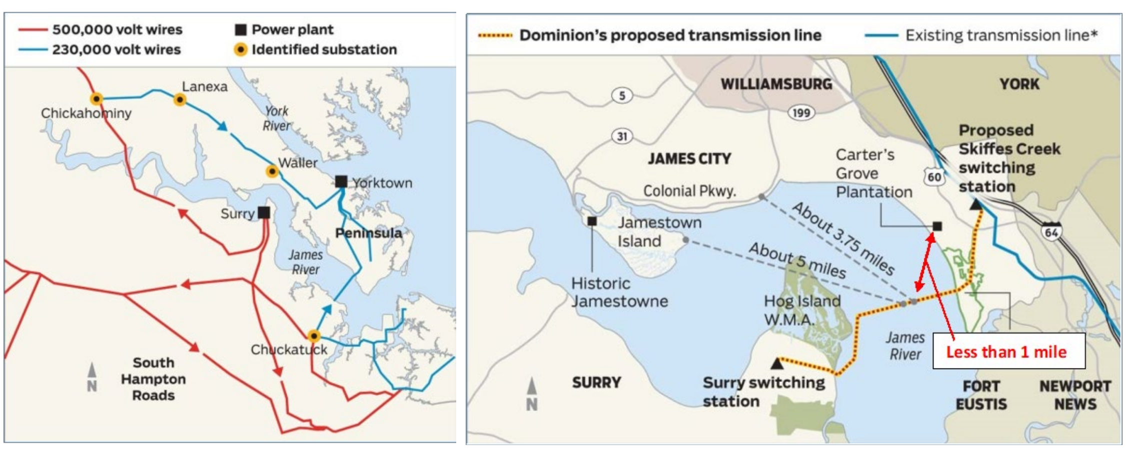
2. The EIS should directly evaluate alternatives to the Surry-Skiffes Creek project that include modularly scaled battery storage,[8] solar PV, and peak load reducing energy efficiency or demand-response options.

3. The EIS should evaluate any incremental costs associated with required energy efficiency, demand response, solar PV, and battery resources needed to ensure that threshold net load levels seen on the transmission system[9] during summer peak periods across the NHRLA are below those required to ensure compliance with NERC transmission operation standards.

Dominion asserts that the Surry-Skiffes Creek-Whealton project is needed to maintain electric reliability in the NHRLA

The Surry-Skiffes Creek-Whealton project has three components—the Surry-Skiffes Creek 500 kV transmission line, the Skiffes Creek-Whealton 230 kV transmission line, and the Skiffes Creek 500-230-115 kV switching station. The basis for the Project is Dominion's reported need for new transmission capacity to move electricity into and out of the NHRLA and maintain electric reliability on the Peninsula while meeting Dominion's projected load growth and allowing for coal plant retirements. ES Figure 1 shows the transmission lines and infrastructure existing before the Project was built and the location of the 500 kV Surry-Skiffes Creek project.

ES Figure 1: Existing transmission lines and switching stations (2015) in Hampton Roads (left)
Proposed new 500 kV transmission line path and switching station, with distances to cultural resources (right)

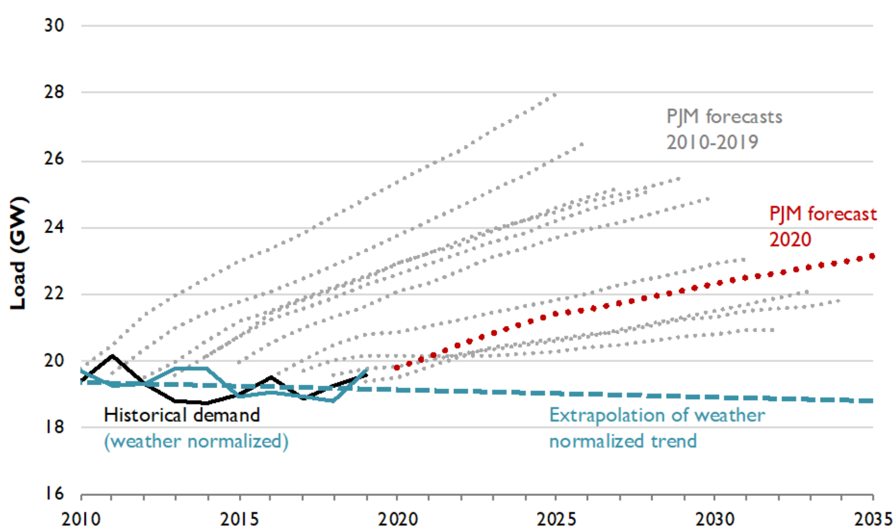


Source: PJM Regional Transmission Organization, 2015 and; National Parks Conservation Association and Princeton Energy Resources International, November 2015.

Dominion has systematically over-projected demand to justify building the project…but may actually have a capacity surplus even without the Project

Dominion relied on power flow modeling to justify building the Surry-Skiffes Creek project in its 2012 application to the Virginia State Corporation Commission (SCC). However, the load growth assumptions that Dominion relied on dramatically overstate future energy demand. In fact, PJM, the regional transmission operator responsible for coordinating the movement of electricity in Virginia,[10] and Dominion have consistently and systematically overestimated the summer peak load in the Dominion Zone[11] (ES Figure 2) and the NHRLA (ES Figure 3).[12] Publicly available data show that summer peak load levels in the NHRLA have flattened out and declined materially, if not dramatically, in comparison to Dominion's earlier projections. Our analysis shows year-over-year peak load trends will continue to be flat or declining over the next decade, ensuring no future need for the James River crossing segment of the Project.[13] These findings undermine Dominion's claims (from its 2012 initial application,[14] and from its more recent 2016 issuances[15]) that the Surry-Skiffes Creek project, and especially the additional 500 kV source provided by the new James River crossing component, would be needed in part because of continuing load increases.[16]

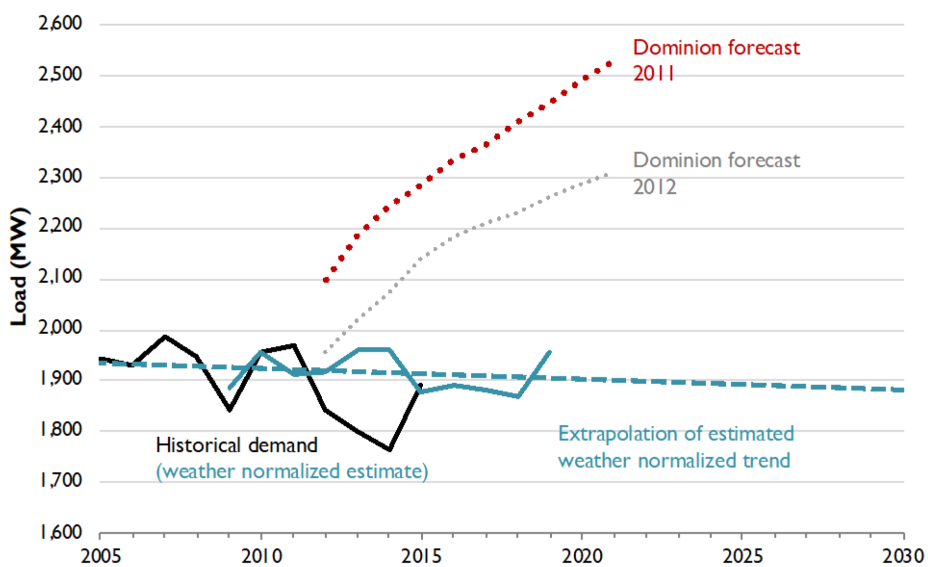
ES Figure 2: Summer peak electricity demand in the PJM Dominion Zone (2010–2035)



Note: Compared to the historical trend in summer peak demand, PJM historically overestimated load in the Dominion Zone. The equivalent compound annual growth rates for the trendlines are: PJM 2011 forecast, 2.0% (first gray dotted line); PJM 2020 forecast (red dotted line), 1.0%; historical demand 2009 to 2019, 0.8% (black solid line); historical weather normalized demand from 2009 to 2019, 0.4% (blue solid line). The extrapolation of the weather normalized trend (blue dotted line) is based on a least squares regression of historical weather normalized demand from 2009 to 2019 and is equivalent to an annual decline of 0.1%. Data sources: PJM Resource Adequacy Planning Department. 2009-2019. PJM Load Forecast Reports, January 2010-2020.

As shown in ES Figure 3, Dominion projected in 2011 that the NHRLA peak load would be 2,100 MW in 2012 and would increase to 2,532 MW in 2021.[17] This 432 MW increase is equivalent to a compound annual growth rate of 2.1 percent.[18] Yet Dominion's projected 432 MW load increase did not materialize. Dominion's current load projection for 2021 is 1,998 MW,[19] which is equal to a compound annual growth rate of 0.15 percent during the period from 2011 to 2021. Our analysis shows that based on recent trends, the 2021 peak load is likely to be 1,900 MW, which is a 69 MW decrease compared to 2011, or a compound annual growth rate of *negative* 0.3 percent. These differences matter: a lower peak load means that less power is required from the lines importing power into the NHRLA to meet needs under contingency conditions (i.e., when the transmission system is stressed).

ES Figure 3: Summer peak electricity demand in the NHRLA



Note: Compared to the historical trend in summer peak demand, Dominion historically overestimated load in the NHRLA. The equivalent compound annual growth rates for the trendlines are: Dominion 2011 forecast, 2.1% (red dotted line); Dominion 2012 forecast (gray dotted line), 1.8%; historical demand 2009 to 2019, negative 0.3% (black solid line); estimated historical weather normalized demand from 2009 to 2019, 0.4% (blue solid line). The extrapolation of the estimated weather normalized trend (blue dotted line) is based on a least squares regression of estimated historical weather normalized demand from 2009 to 2019 and is equivalent to an annual decline of 0.1%. Data sources: Application of Virginia Electric and Power Company for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, Skiffes Creek 500 kV-230 kV-115 kV Switching Station; Application No. 257. 2012. PJM Resource Adequacy Planning Department. 2009-2019. PJM Load Forecast Reports, January 2010-2020.

We correct Dominion's over-projected demand forecasts by extrapolating historical load growth patterns and applying them to current load data to develop an adjusted load forecast out through 2030. We use Dominion's analyses from the 2012–2016 period to infer "safe" peak load levels while importing electricity to the NHRLA under contingency conditions. We evaluate a range of possible future load requirements and resource needs, including an extremely conservative scenario where the NHRLA faces a capacity shortfall of 250 MW, which we meet with battery storage. For our base case, we start with the most recent transparent and clear source of data on capacity limits to the NRHLA without the Project: Dominion's 2012 project application. We also evaluate a case based on Dominion's updated generation-only alternatives analysis. We find that without the Project, between 2021 and 2030,[20] the region would likely have between 83 MW of surplus capacity (base case) and a shortfall of 77 MW of capacity (generation-only alternatives case).

The U.S. Army Corps also claims that "peak load, while relevant, is not the only applicable criteria that must be considered. Power flow modeling studies must be conducted to evaluate whether an alternative meets North American Electric Reliability Corporation (NERC) Reliability Standards at all points in the system under all contingencies."[21] While it is true that any resource portfolio would need to be operationally validated by power flow modeling, this holds true for all resource planning exercises, whether they are completed by using production cost and capacity expansion modeling, or simple spreadsheet analysis. This statement incorrectly conflates the need to validate and verify proposed solutions with power flow modeling with the inability to identify alternatives that are likely to meet system needs.

Dominion's alternatives analysis failed to consider locally sited battery storage, renewables, and demand-side management

To meet anticipated future electrical needs, Dominion focused on transmission-only solutions. Dominion eventually evaluated generation-only alternatives only after the company was ordered to do so by the hearing examiner.[22] However, Dominion's generation alternative involved a $1.3 billion plan to retrofit and repower Yorktown 1, 2, and 3 and then build a new gas plant and firm gas transportation infrastructure.[23] In evaluating generating alternatives, Dominion explicitly stated that it did not consider wind and solar because of cost and site availability, and it made no mention of battery storage.[24]

Reliability analyses conducted by Dominion in 2012 through to as late as January 2016[25] never included utility-scale battery storage resources as part of any alternative solution. Yet the dramatic decline in battery resources costs makes it reasonable to include battery storage in an analysis of alternatives. Battery storage comes in smaller capacity increments than the fossil resources tested as "stand alone" generation alternatives,[26] directly impacting the contingency conditions reflected in power flow modeling as they are less "lumpy"[27] than conventional generation alternatives. They also require no new fossil fuel infrastructure and are instantaneously responsive to a contingency event.

Battery storage resources, especially when synergistically coupled with the effects of lower peak load and the presence of relatively inexpensive solar PV in the NHRLA, present an entirely different set of resource options for consideration in power flow modeling studies than what has been studied previously. The question is not whether an alternative could reliability provide electricity service to the NHRLA—it most certainly can. Rather, the question is: what is the lowest level of battery resource required to ensure such reliable operation in the NHRLA, under a range of installed energy efficiency measures and solar PV? Modular, potentially emissions-free, dispatchable, flexible battery storage can be leveraged to ensure reliable operation at least cost, without the Surry-Skiffes Creek project. While only power flow modeling can pinpoint the exact MW value of battery resource required, we present a reasonable technical analysis to demonstrate that even across a range of need, these alternative solutions are cost-effective in comparison to the cost of the Surry-Skiffes Creek project.

Dominion also did not consider demand-side management solutions. In fact, the Army Corps claimed that energy efficiency and other demand-side management options cannot be used to address NERC reliability concerns.[28] This is simply not accurate, and it reflects a misunderstanding of the manner in which energy efficiency resources help. While not a controllable resource, they do predictably reduce peak demand and thus provide a critical measure of reliability benefit. Demand response and energy efficiency can reduce end-users' coincident peak demand, which is demand at the time that the system is experiencing peak demand.[29]

Synapse finds that alternative resource portfolios can meet reliability standards at a cost equal to—and potentially much lower than—the $443.5 million Project

We design three alternative resource portfolios composed of different quantities of local battery resource, solar PV, and peak reduction gained through energy efficiency. When coupled with existing transmission infrastructure,[30] these alternatives are able to provide the Peninsula the incremental capacity, grid services, and potentially more energy that it needs in the absence of the Project (ES Table 1). We estimate the range of costs incurred and examine the operational characteristics and the capability of these alternatives to maintain NERC-compliant system reliability by assessing the extent to which they minimize power import needs for the NHRLA under contingency conditions.

ES Table 1: Local alternatives—summary range of cost, $ millions

Local Need	Resource Option Combination		
	Battery Only	**Battery + Energy Efficiency + Solar PV**	**Battery + Solar PV**
Low – 67 MW	$80	$112	$138
Med – 77 MW	$93	$130	$160
High – 250 MW	$301	$420	$516
	Project construction cost		
Surry-Skiffes Creek Transmission project	$443.5 million to date (including $95.5 million for mitigation activities)[31]		

Note: In all scenarios, battery resources also provide incremental voltage support for the NHRLA.

These alternatives can be locally sourced and allow for reliable operation of the power system in the region without a need for the Surry-Skiffes Creek project, and without a need for new fossil fuel generation at Yorktown or anywhere in the NHRLA. The availability and operation of these new local alternative resources during peak load periods would create headroom on the existing 230 and 115 kV system. This would allow reliable operation even when one or more of those lines may not be available, or are forced out of service, when reflecting the type of contingency condition that is the focus of reliability studies. The best local alternatives also include increasing amounts of peak-load-reducing energy efficiency, which already has contributed to noticeable and noteworthy reductions in the peak load experienced, and forecasted, for the NHRLA.

Lower load coupled with local non-fossil fueled supply, and excluding the new transmission across the James River, complete an optimal resource plan for the NHRLA. Recent, transformative technological improvements and dramatic cost declines tied to solar PV and utility-scale battery storage shape a cost-effective resource package that make the Surry-Skiffes Creek project unnecessary, all while adhering to stringent, contingent-condition reliability standards mandated by NERC and the Federal Energy Regulatory Commission (FERC).[32] Utility-scale solar PV costs dropped around 50 percent between 2013 and 2018.[33] Battery storage costs have also decreased 50 percent[34] over a similar period. Taken together, and considering different combinations of these resources, our analysis shows that reliability standards can be met at a cost—at most—roughly equal to the Surry-Skiffes Creek project cost of $443.5 million, and potentially at significantly lower costs.[35]

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[1] The NHRLA includes approximately 285,000 electric utility customers across jurisdictions on the Peninsula (counties of Charles City, James City and York and the cities of Williamsburg, Yorktown, Newport News, Poquoson, and Hampton), Middle Peninsula (counties of Essex, King William, King and Queen, Middlesex, Mathews, Gloucester, and City of West Point), and Northern Neck (counties of King George, Westmoreland, Northumberland, Richmond and Lancaster, and the City of Colonial Beach).

[2] Virginia Senate Bill 966 Electric utility regulation; grid modernization, energy efficiency. Available at https://lis.virginia.gov/cgi-bin/legp604.exe?181+sum+SB966.

[3] Virginia House 1526 Electric utility regulation; environmental goals. Available at https://lis.virginia.gov/cgi-bin/legp604.exe?201+sum+HB1526.

[4] Commonwealth of Virginia website, *Governor Northam Signs Clean Energy Legislation*, April 12, 2020. Accessed May 3, 2020. Available at https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html.

[5] This project has three components: the Surry-Skiffes Creek 500 kV overhead transmission line, the Skiffes Creek-Whealton 230 kV transmission line, and the Skiffes Creek 500-230-115 kV switching station. The 500 kV overhead transmission line is subject to permitting by the Army Corps of Engineers.

[6] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

[7] Battery storage resources offer instantaneous frequency response and voltage control to nimbly support both normal and abnormal system conditions in the region and could be especially valuable in ensuring prevention of low voltage cascading outage concerns under extreme contingency conditions.

[8] Utility-scale battery storage can be configured as smaller, modular units on the order of tens of MW, even if the total resource capacity is multiple hundreds of MW. Power flow modeling should reflect such modularity.

[9] Local solar PV and battery resources have the effect of reducing the "net" imports to the NHRLA seen on the underlying transmission system.

[10] PJM (PJM Interconnection LLC, acronym based upon "Pennsylvania, Jersey, and Maryland") is a regional transmission organization that is responsible for coordinating the movement of electricity in all or parts of thirteen states, including Virginia, and the District of Columbia.

[11] The Dominion Zone is the geographic region within PJM's jurisdiction in which Dominion provides electrical service; it includes most of Virginia, including the NHRLA, and part of eastern North Carolina.

[12] The Virginia SCC confirms this. "The Commission recognizes that every forecast has strengths and weaknesses and that no forecast will exactly match actual results except by chance; however, weighing the evidence presented in this proceeding, the Commission has considerable doubt regarding the accuracy and reasonableness of the Company's load forecast for use to predict future energy and peak load requirements." VA SCC, Dominion IRP Order, Case UR-2018-00065, December 7, 2018, page 7.

[13] Our analysis relies on Dominion's estimates of reliable operation without any portion of the Project. Removing the James River crossing segment while leaving in place other aspects of the Project would effectively create additional headroom for reliable operation in the NHRLA.

[14] Application of Virginia Electric and Power Company for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, Skiffes Creek 500 kV-230 kV-115 kV Switching Station (Dominion Application); SCC, Case No. PUE-2012-00029, June 2012.

[15] February 1, 2016 letter from Dominion to NPCA, available at https://www.nao.usace.army.mil/Portals/31/docs/regulatory/Skiffes/Section%20106/10_02.1.2016_Dom_Response_to_NPCA.pdf?ver=2016-06-28-124124-920.

[16] Dominion Application, SCC, Case No. PUE-2012-00029, June 2012. Page 3. "The need for the proposed transmission facilities is being driven by continued load growth in the North Hampton Roads Load Area over the past ten years. Over the 10-year period from 2002 to 2011, peak electrical demand for the North Hampton Roads Load Area grew from 1767 MW to 1969 MW, an increase of 11.4 percent. In addition, load projections (based on the 2012 PJM Load Forecast) indicate load will grow an additional 351 MW between 2012 and 2021."

[17] Dominion Application, SCC, Case No. PUE-2012-00029, June 2012. Appendix, page 22.

[18] Compared the 2011 actual load of 1,969 MW, Dominion's forecasted growth by 2021 is even greater: 563 MW, or a compound annual growth rate of 2.5 percent.

[19] PJM Load Forecast Report, January 2020. NHRLA load calculated as a portion of Dom Zone – assuming NHRLA accounts for 9.9 percent of total Dominion load.

[20] We bound our analysis by 2030 in line with standard IRP practices that focus on the next 10–15 years. With slow or no load growth in the NHRLA and rapidly changing system conditions, resource planning should focus on modular and incremental resources that can be built as needed, rather than large centralized resources that are built all at once and cannot be downsized or reduced if/when Dominion's projection of load growth does not materialize.

[21] Dominion Report: Surry-Skiffes Creek -Whealton, Modeling and Alternatives Analysis Review. February 11, 2016.

[22] Motion of Virginia Electric and Power Company for leave to extend procedural schedule in order to conduct studies requested by staff and request for expedited treatment. January 2013. SCC, Case No. PUE-2012-00029.

[23] Rebuttal testimony of G. Kelly, page 22. SCC, Case No. PUE-2012-0029.

[24] *Id*, page 16.

[25] Dominion response to NPCA, February 1, 2016. Available at https://www.nao.usace.army.mil/Portals/31/docs/regulatory/Skiffes/Section%20106/10_02.1.2016_Dom_Response_to_NPCA.pdf?ver=2016-06-28-124124-920.

[26] Dominion tested modified versions of "stand alone generation" using 620 MW of new or retrofitted coal or gas generation only. G. Kelly, Rebuttal Testimony. SCC, PUE-2012-0029. Section V and VI.

[27] Utility-scale battery storage resources are often installed, and modeled, at tens of MW capacity levels, rather than the hundreds of MW scale used by Dominion when testing supply-only options in 2012. This means that contingency events reflecting a supply resource outage are much smaller.

[28] USACE Preliminary Alternatives Conclusions White Paper RE: NAO-2012-0080 / 13-V0408. October 1, 2015.

[29] Coincident peak demand refers to the demand from a particular user or sub-region at the time that the NHRLA is experiencing peak demand. This is in contrast with non-coincident peak demand, which refers to the peak demand of a specific end-user or region.

[30] There are currently four 230 kV transmission lines providing power to the NHRLA: two originating from the north and running down the Peninsula to Newport News, and two originating from the south, which connect to Norfolk, entering the Peninsula via towers close to the James River Bridge (these lines interconnect the NHRLA with the SHRLA). There are also two 115 kV circuits in the north.

[31] Project cost update provided by Dominion during a virtual stakeholder meeting convened by the USACE on April 23, 2020. David DePippo, an attorney for Dominion Energy, stated that Dominion had sent the Corps a letter stating that the actual costs of the Surry-Skiffes Creek Project totaled $443.5 million: $348 million construction plus $95.5 million for mitigation.

[32] FERC is the federal agency that regulates, among other things, the transmission and wholesale sale of electricity and natural gas in interstate commerce.

[33] Fu, Ran, David J. Feldman, and Robert M. Margolis. US solar photovoltaic system cost benchmark: Q1 2018. No. NREL/TP-6A20-72399. National Renewable Energy Laboratory (NREL), Golden, CO (United States), 2018.

[34] Lazard Levelized Cost of Storage Version 1.0, November 2015. Lazard Levelized Cost of Storage Version 5.0, November 2019. LCOE of peaker-replacement 4hr lithium Ion batteries.

[35] PJM interconnection cost data, by project component.

1. INTRODUCTION

1.1. Scope of this report

In this report, we conduct an examination of alternative supply and demand-side options to serve the electrical needs of the North Hampton Roads Load Area (NHRLA)[1] on the Peninsula, including battery storage, solar PV, energy efficiency, and demand response. These resources can provide a portion of the capacity, ancillary services, and energy that the NHRLA region may need in the absence of the Surry-Skiffes Creek-Whealton project. With them, existing underlying 230 kV and 115 kV infrastructure can reliably provide the remaining needs. We evaluate alternative resource options *as if the transmission line had not yet been built*.[2]

In this report, we:

1. Evaluate the system needs that the Project was designed to address, as expressed by Dominion in its original 2012 application to the Virginia State Corporation Commission (SCC). Our analysis builds off Dominion's original analysis on load that can be met by the existing generation resources and transmission system; we do not base our analysis on independent power-flow modeling of the transmission system.

2. Review the alternative analyses presented by other parties (specifically Tabors[3] and Stantec[4]) and discuss Dominion's response to each analysis. We evaluate and update demand forecasts and resource portfolios for the entire Dominion region and the NHRLA based on public data from Dominion and from PJM, the regional transmission operator responsible for coordinating the movement of electricity in Virginia and 12 other states.[5]

[1] The NHRLA includes approximately 285,000 electric utility customers across jurisdictions on the Peninsula (counties of Charles City, James City and York and the cities of Williamsburg, Yorktown, Newport News, Poquoson, and Hampton), Middle Peninsula (counties of Essex, King William, King and Queen, Middlesex, Mathews, Gloucester, and City of West Point), and Northern Neck (counties of King George, Westmoreland, Northumberland, Richmond and Lancaster, and the City of Colonial Beach).

[2] It is beyond the scope of this review to evaluate whether the transmission line should be removed.

[3] The National Trust for Historic Preservation retained the firm of Tabors Caramanis Rudkevich (Tabors) to identify alternatives to the Project that would not require an overhead crossing of the James River and would meet all relevant planning and reliability criteria.

[4] Stantec Consulting Services, Inc. prepared an alternatives analysis on behalf of Dominion for the U.S. Army Corps of Engineers.

[5] PJM (PJM Interconnection LLC, acronym based upon "Pennsylvania, Jersey, and Maryland") is a regional transmission organization that is responsible for coordinating the movement of electricity in all or parts of 13 states, including Virginia, and the District of Columbia.

3. Directly consider the key role of battery resources as capacity options. These were not initially considered by Dominion.

4. Design several alternative resource portfolios that, when coupled with existing transmission,[6] are able to provide the Peninsula the capacity, grid services, and potentially more electricity than it needs in the absence of the Project. Note that the system constraints we assess are based on system capacity, that is the maximum amount of electricity that can be generated on or delivered to the Peninsula on an instantaneous basis.

5. Examine the cost, operational characteristics, and the capability of these alternatives to maintain system reliability in compliance with national grid reliability standards as set by the North American Electric Reliability Corporation (NERC)[7] by assessing the extent to which they minimize power import needs for the NHRLA under contingency conditions.

1.2. Overview of the Surry-Skiffes Creek 500 kV transmission line project

In June 2012, Dominion Energy (serving electric customers in Virginia through its subsidiary Virginia Electric and Power Company) applied to the state utility commission (the Virginia State Corporate Commission or SCC) for approval and certification of a new transmission project. This Project has three components—the Surry-Skiffes Creek 500 kV transmission line, the Skiffes Creek-Whealton 230 kV transmission line, and the Skiffes Creek 500-230-115 kV switching station—and will be referred to in this report as "Surry-Skiffes Creek project" or "the Project." The basis for the Project was Dominion's reported need for new transmission capacity to move electricity into and out of the NHRLA to maintain electric reliability on the Peninsula.

Specifically, Dominion stated the need for new infrastructure was driven by two factors: (1) expected growth in demand for electricity (load growth); and (2) accelerated retirements of coal-fired power plants in the area due to federal policies that required power generation facilities to reduce emissions of mercury and other toxic air pollutants.[8] We evaluate Dominion and PJM's claim that demand for electricity is growing in the Dominion Zone, and specifically in the NHRLA, in Section 2 of this report.

Since Dominion filed its application for the Project in 2012, the company has retired six coal-fired units in the region: four Chesapeake units nearby in the South Hampton Roads load area (SHRLA) at the end of 2014 and Yorktown Units 1 and 2 in the NHRLA in 2019. Dominion's planned retirement of the Yorktown coal-fired power plants directly reduced the quantity of electricity that Dominion could

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[6] There are currently four 230 kV transmission lines providing power to the NHRLA: two originating from the north and running down the Peninsula to Newport News, and two originating from the south, which connect to Norfolk, entering the Peninsula via towers close to the James River Bridge (these lines interconnect the NHRLA with the SHRLA). There are also two 115 kV circuits in the north.

[7] NERC is a not-for-profit international regulatory authority whose mission is to ensure the effective and efficient reduction of risks to the reliability and security of the grid.

[8] The Mercury Air and Toxics Standards (MATS) Rule was established by the U.S. Environmental Protection Agency (EPA) in 2011.

generate with existing capacity on the Peninsula to serve load in the area. In order to meet electricity demand, Dominion asserted that it had to either build more local generation resources or import electricity from outside the Peninsula over new transmission lines. Dominion's retirement of the Chesapeake coal-fired units in the adjacent region, while important, did not impact local generation capacity. Instead, the retirements reduced the amount of electricity available to import onto the Peninsula from the south to meet demand. Dominion's ability to import electricity into the NHRLA from the south, however, is not solely determined by the availability of the Chesapeake units; it is also influenced by the amount of electricity demand in the SHRLA and the availability of other generation resources in or available to import into the SHRLA. In Section 2 of this report, we review the electricity demand in the geographic area served by Dominion (which includes the SHRLA) and identify Dominion's plans for substantial new generation interconnecting into the SHRLA.

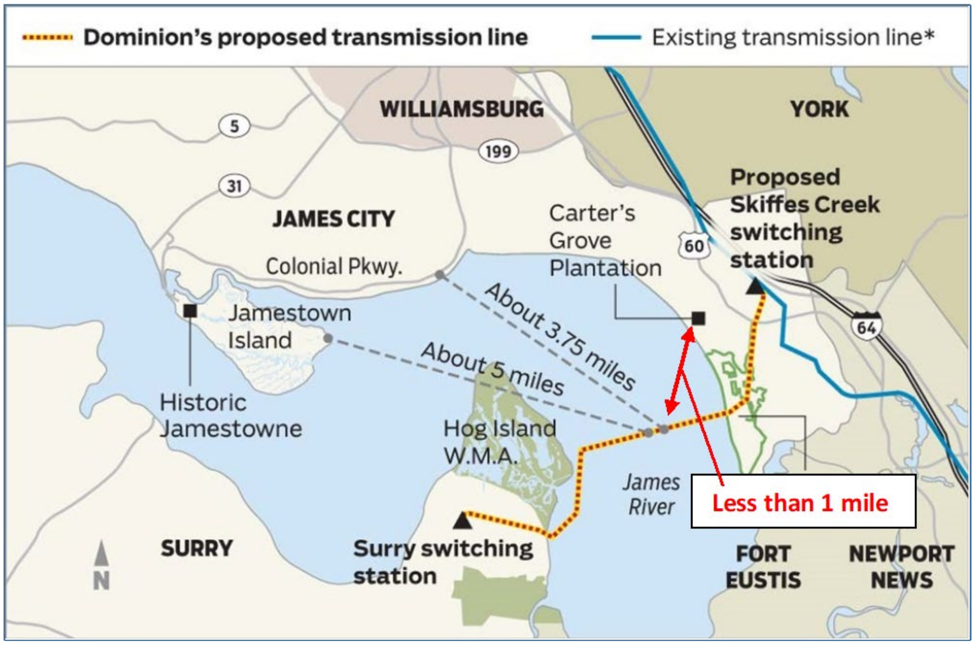
Given Dominion's plan to retire the coal units and, especially, the company's expectations around summer peak load growth, Dominion proposed the Project to alleviate the company's forecasted constraints on the transmission lines serving the NHRLA under contingent conditions. As shown in Figure 1, Dominion designed the Surry-Skiffes Creek 500 kV transmission line to cross the James River east of the Surry Nuclear Plant, connecting the existing Surry substation to a new switching station on the Peninsula at Skiffes Creek. Dominion also included a new 230-kV line to carry the power south from Skiffes Creek along the existing Peninsula transmission route.

The Project would add to Dominion's existing transmission infrastructure on the Peninsula. Dominion currently has four 230 kV transmission lines that provide power to the Peninsula: two originating from the north and running down the Peninsula to Newport News, and two originating from the south. The latter two connect to Norfolk, entering the Peninsula via towers close to the James River Bridge (these lines interconnect the NHRLA with the SHRLA). Dominion also has two 115 kV circuits in the north. According to Dominion, historically these lines together served to import about 40 percent of the annual electricity consumed in the NHRLA,[9] although with the retirement of Yorktown Units 1 and 2 in 2019, this share would have increased substantially without the Project.[10] Figure 1 and Figure 2 below depict the existing transmission lines before the Project, and the proposed path of the Project's transmission line.

[9] Application of Virginia Electric and Power Company for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, Skiffes Creek 500 kV-230 kV-115 kV Switching Station (Dominion Application); SCC, Case No. PUE-2012-00029, June 2012. Appendix, page 19.

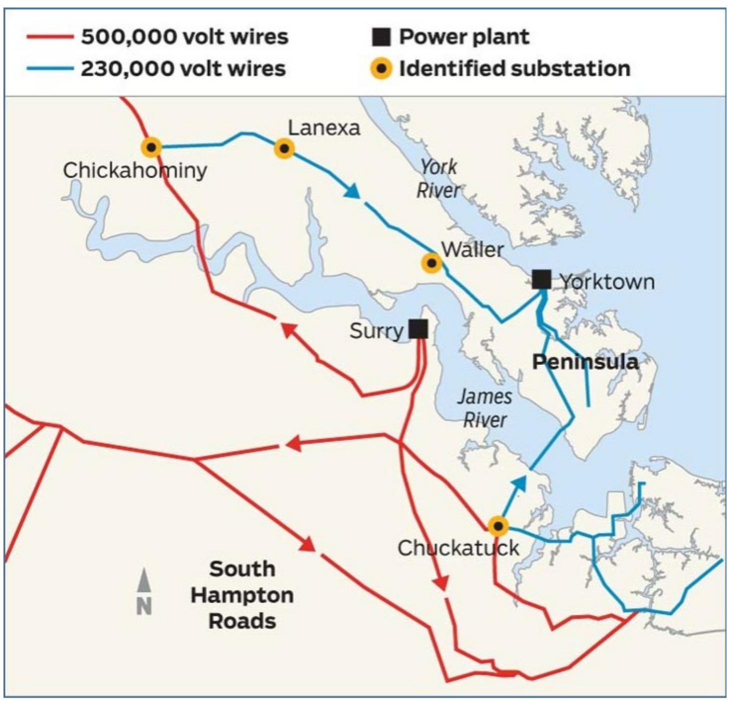
[10] A reminder that here we are referring to the share of energy imported onto the Peninsula over the course of the year, not a change in the instantaneous capacity of the lines to move electricity in and out of the Peninsula.

Figure 1: Proposed Surry-Skiffes Creek 500 kV transmission line path and switching station, with distances to cultural resources



Source: National Parks Conservation Association and Princeton Energy Resources International, November 2015.

Figure 2: Existing transmission lines and switching stations (2015) in Hampton Roads



Source: PJM Regional Transmission Organization, 2015.

Various parties have joined the National Parks Conservation Association (NPCA) in opposing construction of the Project on the basis of adverse impacts to tourism, cultural and historic resources, environment, and potentially the local economy. Among others, these parties include the National Trust for Historic Preservation, and the Association for the Preservation of Virginia Antiquities. Despite opposition, the Project proceeded. Here is a brief timeline of the Project up until now:

- June 2012: Dominion applies to the SCC for approval and certification of the Project
- November 2013 through December 2015: Virginia SCC grants approval of the Project through various Orders
- December 2014: Dominion retires 650 MW of coal-fired generation capacity at the Chesapeake Power Station in the SHRLA.
- July 2017: The U.S. Army Corps of Engineers (Army Corps) issues a permit for the Project. Dominion proceeds with construction of the Project under this permit
- July 2017: NPCA and others file suit in U.S. District Court for the District of Columbia contesting the Army Corps' failure to complete an Environmental Impact Statement (EIS) including evaluating reasonable alternatives
- May–June 2018: U.S. District Court upholds the Army Corps' decision to issue the permit; plaintiffs file appeal in the U.S. Court of Appeals for the District of Columbia Circuit
- February 2019: Dominion electrically energizes the new line
- March 2019: In *National Parks Conservation Association* v. *Semonite*, the U.S. Circuit Court of Appeals reverses the District Court decision, and instructs the Army Corps to complete an EIS as required by the National Environmental Policy Act (NEPA)
- March 2019: Dominion retires 375 MW of coal-fired generation capacity (Yorktown 1 & 2) at the Yorktown Power Station in the NHRLA

Throughout the permit review process, NPCA, the National Park Service, and many other agencies, advocacy groups, officials, and concerned citizens advised the Army Corps and Dominion that an EIS was required for this controversial Project. Dominion built the Project despite legal challenges to its permit. Now the Army Corps is preparing an EIS to evaluate alternatives to the Project and review factors affecting the public interest. The alternatives under evaluation by the Army Corps include, but are not limited to, a "no action" alternative if the Project is deemed unnecessary, energy efficiency and load management practices, changes to existing power generation facilities, construction of new power generation facilities, building other transmission lines, and combinations of these alternatives.[11]

[11] USACE Preliminary Alternatives Conclusions White Paper; RE: NAO-2012-0080/13-V0408. October 1, 2015.

2. Resource Planning for Transmission Security in the North Hampton Roads Load Area

In this section we review and evaluate information on the electrical needs (associated with meeting electricity peak load) of the NHRLA and transmission import and local capacity resources available to meet those needs. We summarize the constraints on the system based on prior analysis performed by Dominion and other parties and assess Dominion and PJM's assertions regarding the quantities of additional resources required to meet NHRLA needs. We recognize that contingency conditions—i.e., system operation after loss of infrastructure—are an important driver of need, but that peak load projections, especially when flat or declining, are critically important to such an assessment. As a key starting point, we use Dominion's NERC-compliant system in the period prior to retirement of the Yorktown coal units, absent the presence of the Project.

2.1. Electric power load and supply forecast in the NHRLA

On June 11, 2012, Dominion submitted an application to the SCC for approval and certification of the new transmission project, including the Surry-Skiffes Creek 500 kV transmission line, the Skiffes Creek-Whealton 230 kV transmission line, and the Skiffes Creek 500-230-115 kV switching station.[12] In the application, Dominion stated the need for the new infrastructure to maintain compliance with NERC reliability standards while serving load in the NHRLA.[13] Specifically, Dominion supported its application for the Project with the assertion that the transmission line would address NERC violations expected to occur in the summer when the thermal rating of transmission equipment is lower because higher ambient temperature can cause lines to overheat (which can damage the lines).[14] Thermal conditions in the summer limit the amount of electricity that can move in and out of the area and therefore place more extreme limits on the system than would an extreme winter load caused by, for example, a "polar vortex." In an extreme winter scenario, demand in the NHRLA would be high, but the transmission lines would not be limited by thermal conditions.

Dominion expected summer NERC violations to result from two main factors:

1. **The anticipated retirements of two coal-fired power plants in the area (summarized below in Table 1).** The retirement of Yorktown 1 & 2 ultimately was delayed until 2019 based on the purported need to keep the units online to meet NERC reliability standards until the Project was completed.

[12] Dominion Application. SCC, Case No. PUE-2012-00029. June 2012.

[13] *Id*, pages 1-2.

[14] *Id,* page 3.

2. **Projected load growth in the NHRLA between 2012 and 2021**. In the application, Dominion estimated that load in the NHRLA would grow by 351 megawatts (MW) or 18 percent between 2012 and 2021.

Table 1: Dominion's planned generation retirements in the NHRLA

Load area	Plant	Capacity MW	Anticipated retirement date (Dom. project application)	Actual retirement date	Retirement included in Dom. 2012 power flow modeling
NHRLA	Yorktown Unit 1	159	12/31/14	3/8/19	Yes
NHRLA	Yorktown Unit 2	156	12/31/14	3/8/19	In select cases, but not in baseline
NHRLA subtotal		**315**			
SHRLA	Chesapeake Unit 1	111	12/31/14	12/23/14	Yes
SHRLA	Chesapeake Unit 2	111	12/31/14	12/23/14	Yes
SHRLA	Chesapeake Unit 3	156	12/31/15	12/23/14	Yes
SHRLA	Chesapeake Unit 4	217	12/31/15	12/23/14	Yes
SHRLA subtotal		**595**			

Note: Dominion cites these retirements in the Project application as driving infrastructure needs. Sources: Application No. 257 of Virginia Electric and Power Company for Approval and Certification of Electric Facilities, PJM Generation Deactivations. Accessed 2/28/2020. https://www.pjm.com/planning/services-requests/gen-deactivations.aspx.

Load in the Dominion area, and the NHRLA area

Synapse reviewed Dominion's historical load data through 2020 as reported in PJM's annual load forecast reports.[15] We found that, since 2009, Dominion's weather-normalized peak summer load[16] for the entire PJM Dominion Zone[17] has been declining at an average rate of approximately 22 MW per year. We note that load projections are not readily available specifically for the NHRLA outside of what Dominion provided in its 2012 Application. We start by discussing load trends and projections in the Dominion Zone as a whole and then evaluate the implications for the NHRLA specifically. See Appendix A for tabular summaries of historical and forecast load data for the NHRLA.

Dominion historical and future load

Despite a clear declining historical trend, PJM (the regional operator that covers Dominion's service territory) consistently assumed steady load growth in the Dominion Zone. Each year, PJM forecasts the load in the Dominion Zone for the next 16 years. We reviewed a series of 11 such forecasts, beginning

[15] PJM Resource Adequacy Planning Department. 2009 through 2019. PJM Load Forecast Report, January 2010 through January 2020. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/prev-load-reports.aspx and https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx.

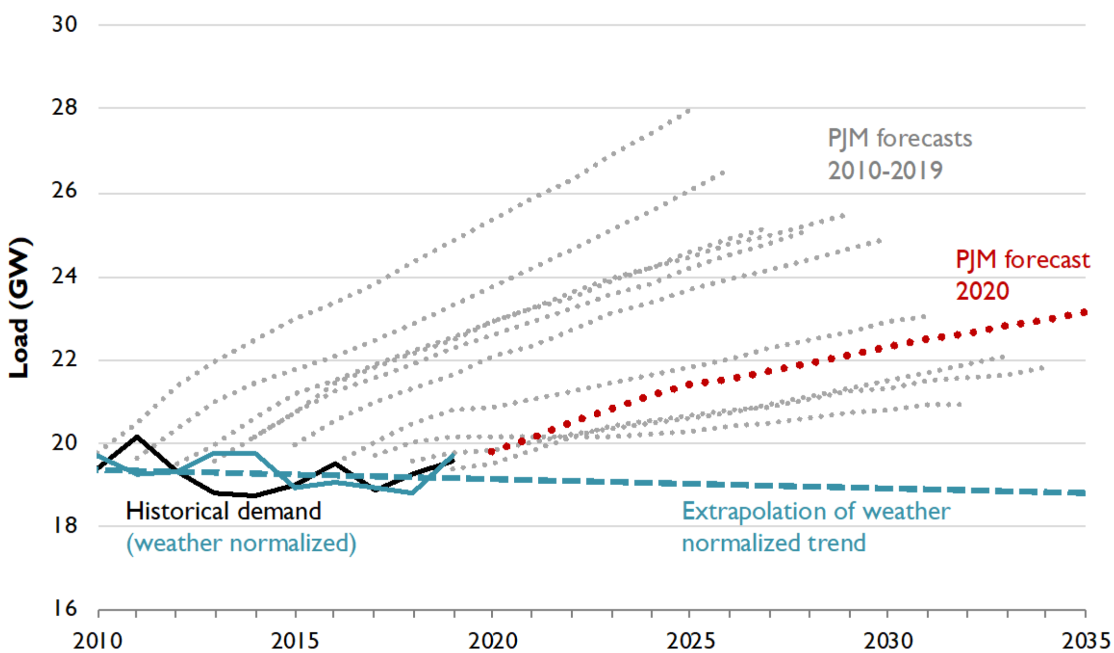
[16] Weather normalization is a process of adjusting energy or peak load to what would have happened under normal weather conditions. Weather-normalized loads are useful for capturing long-term trends in load growth. The methodology that PJM uses for weather normalization relies on statistical regressions and is constantly evolving. More information on PJM's methodology can be found at https://www.pjm.com/-/media/committees-groups/subcommittees/las/20171115/20171115-item-06-weather-normalization-method.ashx.

[17] Dominion is part of the PJM Regional Transmission Operator (RTO) territory.

with PJM's 2010 forecast (for the period 2010 to 2025) and ending with PJM's 2020 forecast (for the period 2020 to 2035). The compound annual growth rate in these forecasts ranges from 0.4 percent (2017 forecast for the period 2017 to 2032) to 2.3 percent (2010 forecast for the period 2010 to 2025). Figure 3 displays the substantial deviations between PJM's forecasted (dotted gray lines) and actual summer peak demand (black and turquoise solid lines) for Dominion every year since 2010. The difference between PJM's most recent forecasted load (red dotted line) and the trend in actual load extrapolated out to 2035 (dashed turquoise line) exceeds 4,000 MW by 2035.

The historical decline in load within the Dominion Zone reasonably suggests similar patterns in the SHRLA, the load area just south of the NHRLA. The SHRLA and NHRLA are electrically interconnected by two 230 kV transmission lines which enter the Peninsula via towers close to the James River Bridge. Because of their interconnection, a decline in load in the SHRLA results in more electricity available for import into the NHRLA from the south (assuming all other system conditions remain the same).

Figure 3: Summer peak electricity demand in the PJM Dominion Zone (2010–2035)



Note 1: This figure shows that, compared to the historical trend in summer peak demand, PJM historically overestimated load in the Dominion Zone. The equivalent compound annual growth rates for the trendlines are: PJM 2011 forecast, 2.0% (first gray dotted line); PJM 2020 forecast (red dotted line), 1.0%; historical demand 2009 to 2019, 0.8% (black solid line); historical weather normalized demand from 2009 to 2019, 0.4% (blue solid line). The extrapolation of the weather normalized trend (blue dotted line) is based on a least squares regression of historical weather normalized demand from 2009 to 2019 and is equivalent to an annual decline of 0.1%.

Note 2: Historical weather normalized demand varies from year to year, as shown with the solid turquoise line. We project future demand assuming historical trends continue. Specifically, we find the trend, or average annual change in demand historically, as show in the turquoise dotted line, and assume that same pattern continues out to 2035.
Data sources: PJM Resource Adequacy Planning Department. 2009-2019. PJM Load Forecast Reports, January 2010-2020. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/prev-load-reports.aspx and https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx.

NHRLA historical and future load

Turning to just the NHRLA, Dominion included historical NHRLA load data going back to 2005 in its 2012 application to the SCC.[18] These data show a steady decline in the NHRLA's peak summer load between 2005 and 2012, as in Dominion's broader geographic region. NHRLA load profiles roughly mimic Dominion's broader load profile, and load in the NHRLA accounts for approximately 9.9 percent of the Dominion Zone load on average.[19]

Dominion's 2012 application to the SCC also included forecasts of load going forward. These forecasts projected steady load growth in the NHRLA, with an average annual growth rate of 2.1 percent (2011 forecast) and 1.8 percent (2012 forecast).[20] Dominion uses PJM's assumption of steady load growth in the Dominion Zone to substantiate its (Dominion's) claim that load will grow steadily in the NHRLA.[21]

However, as discussed above, this is at odds with historical load, which had been declining in the NHRLA at an estimated rate of 2 MW per year (22 MW annual decline in demand in the Dominion Zone multiplied by 9.9 percent, the portion of the Dominion Zone demand that the NHRLA represents). As seen in Figure 4, there is a substantial difference between actual historical summer peak demand (turquoise solid line) and forecasted demand in the NHRLA (gray and red dotted lines). Further, Dominion's 2011 load forecast, which was used initially to substantiate the need for the project (red dotted line), forecasted demand for 2020 that is 555 MW greater (2,492 MW minus 1,937 MW) than what we would expect for 2020 based on the trend in estimated historical load (turquoise dashed line).

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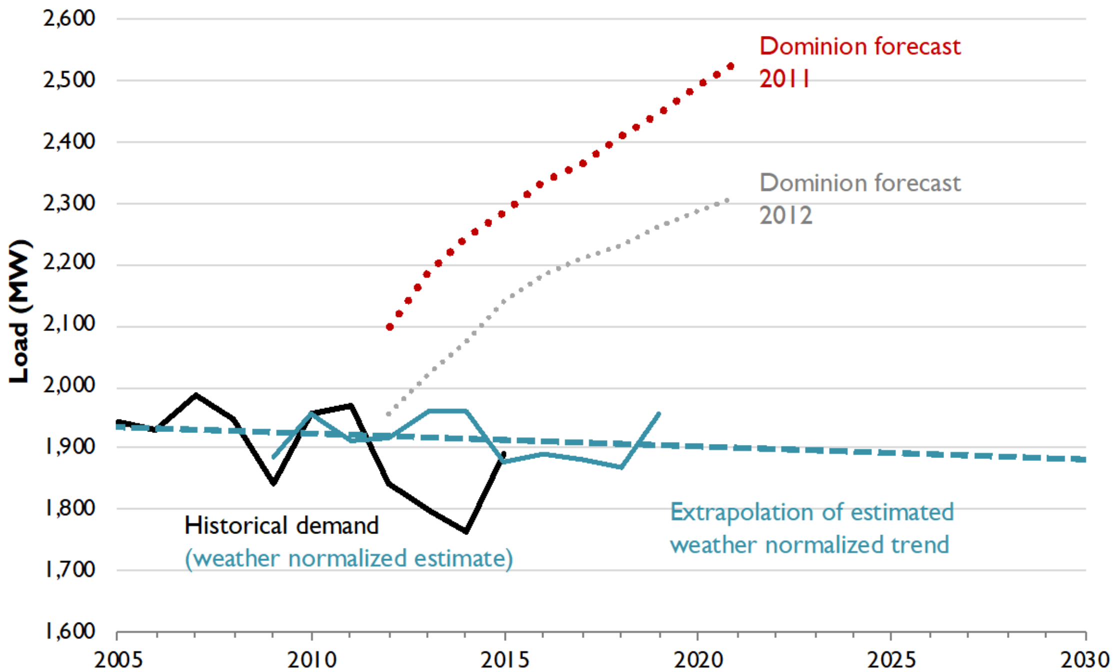
[18] Dominion Application. SCC, Case No. PUE-2012-00029. June 2012. Appendix, page 21.

[19] We don't have actual historical load numbers for NHRLA for the period 2012 to present; however we have actual historical numbers for Dominion as a whole. According to Dominion's 2012 application, load characteristics in the NHRLA roughly mimics those in Dominion as a whole. Therefore, we estimate actual historical load on NHRLA assuming the NHRLA accounts for 9.9 percent of Dominion's total historical load.

[20] Dominion Application. SCC, Case No. PUE-2012-00029. June 2012. Appendix, page 22.

[21] Dominion Application. SCC, Case No. PUE-2012-00029. June 2012. Appendix, pages 15 and 16.

Figure 4: Summer peak electricity demand in the NHRLA



This figure shows that, compared to the historical trend in summer peak demand, Dominion historically overestimated load in the NHRLA. The equivalent compound annual growth rates for the trendlines are: Dominion 2011 forecast, 2.1% (red dotted line); Dominion 2012 forecast (gray dotted line), 1.8%; historical demand 2009 to 2019, negative 0.3% (black solid line); estimated historical weather-normalized demand from 2009 to 2019, 0.4% (blue solid line). The extrapolation of the estimated weather normalized trend (blue dotted line) is based on a least squares regression of estimated historical weather-normalized demand from 2009 to 2019 and is equivalent to an annual decline of 0.1%.

Data sources: Virginia Electric and Power Company. Application of Virginia Electric and Power Company for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, Skiffes Creek 500 kV-230 kV-115 kV Switching Station; Application No. 257. 2012.
PJM Resource Adequacy Planning Department. 2009-2019. PJM Load Forecast Reports, January 2010-2020. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/prev-load-reports.aspx and https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx.

Dominion and PJM systematically overestimate demand

Figure 3 and Figure 4 together show that PJM and Dominion have consistently and systematically overestimated the summer peak load in the Dominion Zone and the NHRLA.[22] The forecasted load growth is a central justification for construction of the Surry-Skiffes Creek project, as explained in

[22] The SCC confirms this. "The Commission recognizes that every forecast has strengths and weaknesses and that no forecast will exactly match actual results except by chance; however, weighing the evidence presented in this proceeding, the Commission has considerable doubt regarding the accuracy and reasonableness of the Company's load forecast for use to predict future energy and peak load requirements." VA SCC, Dominion IRP Order, Case UR-2018-00065, December 7, 2018, page 7.

Dominion's application to the SCC. Given the actual decline in demand, Dominion's justification for the Project appears weak at best.

Our finding that Dominion and PJM overestimated their load forecasts is supported by recent SCC actions and is consistent with previous independent analyses.[23] In 2019, the SCC rejected Dominion's 2018 long-term resource plan, called an Integrated Resource Plan or IRP, on the basis that Dominion's long-term peak and annual energy demand projections were too high. SCC's action to order Dominion to redo its IRP was unprecedented and marked the first time the SCC rejected a Dominion plan as insufficient. The SCC pointed to Dominion's load forecast with a 1.4 percent compound annual growth rate, almost double PJM's 2018 projection of 0.8 percent for the Dominion Zone.[24] The SCC ordered Dominion to re-do its IRP using PJM's forecasts for the Dominion Zone.

Dominion's 2012 analyses indicated that without the Project the existing transmission infrastructure would be insufficient to reliably serve NHRLA load once Yorktown Units 1 and 2 were retired. A critical assumption that drove that finding was Dominion's forecast of increasing peak load in the NHRLA. Dominion projected that increasing load would lead to increased strain on the overall capability to import power into the NHRLA via the two existing transmission corridors under a contingency situation when a portion of that transmission was unavailable. The two corridors (from the south and from the northwest) each contain multiple transmission circuits. Reliable service in this context directly implies adherence to underlying NERC standards. In this section we will review the NERC reliability standards, how they apply in this case, how sensitive Dominion's findings of reliability violation are to peak load level, and the scale and type of local supply resources that are available in 2020 in the NHRLA.

NERC reliability standards ensure system reliability

NERC reliability standards are designed to ensure that: (1) transmission system elements are not thermally overloaded, and (2) transmission system voltages stay within a range required for acceptable operation. Utilities must meet these standards when all equipment is in service and, also, when some equipment is forced out of service under various contingency conditions (e.g., when a line, or multiple lines are out of service due to equipment failure). These conditions must be maintained during the time of the highest system loading (i.e., during summer peak conditions).[25]

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[23] A 2016 report prepared by the NPCA and Princeton Energy Resources International noted that "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." National Parks Conservation Association and Princeton Energy Resources International. DVP's Proposed "Surry-Skiffes Creek project" – Issues and Alternatives, Addendum Report. February 1, 2016.

[24] Virginia Electric and Power Company's 2019 Update to 2018 Integrated Resource Plan, Virginia State Corporation Commission and North Carolina Utilities Commission. Case No. PUR-2019-00141, Docket No. E-100, Sub 157.

[25] As discussed above, constraints on the transmission system are more extreme in the summer than in the winter, therefore system loading condition will be most extreme under high summer peak conditions.

The purpose of the relevant NERC standards is to "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."[26] The standards lay out an extensive series of potential conditions (essentially, different combinations of equipment in or out of service) and indicate the extent to which all load must continue to be served even after the contingency event occurs. In some instances, such as a severe, unexpected, and unusual loss of equipment (e.g., all circuits entering the NHRLA from the northwest fail), some level of "lost load" is allowed under the standards; in other instances, no level of lost load is acceptable (e.g., after the loss of a single 230 kV circuit).

Demand, Supply, and Transmission solutions can address NERC violation on the NHRLA

For the NHRLA, maintaining NERC-compliance effectively requires sufficient resources in the local area to ensure that the transmission lines into the area remain operational (within their ratings) after a contingency event causes the remaining lines to be more severely loaded than would normally be seen on a peak load day. In other words, if an equipment failure forces one or more of the lines into the area out of service, and that happens to occur on a peak summer day, the "net load" level[27] must be low enough to be reliably served by the remaining lines into the region, and the voltage must be maintained.

These reliability constraints can be met essentially in three ways:

1. Demand-side management: Load in the region can be reduced or held constant below threshold levels that support reliable operation even during contingency events, through energy efficiency and demand response.
2. Supply-side resources: Additional sources of generation can be added in the NHRLA (especially resources with firm peak capacity)[28] to lower the need for imports into the NHRLA during peak periods after a contingency event.
3. Transmission alternatives: The import capacity of the transmission network (existing and new) into the NHRLA can be increased.

Our report focuses on the first two of these two mechanisms, whereby lower load levels resulting from more efficient use of electricity minimize the level of imported power needed after a contingency event; or the use of battery storage and solar PV resources helps to lower the NHRLA load that needs to be supplied from imports over the existing transmission system. Other analyses, such as that conducted by Tabors, address transmission alternatives.

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[26] North American Electric Reliability Corporation, *Standard TPL-001-4 – Transmission System Planning Performance Requirements*. http://www.nerc.com/files/TPL-001-4.pdf.

[27] By "net load" level we mean the area load minus any generation resources online that are located within the area.

[28] Firm peak capacity refers to the amount of energy available for production which can be guaranteed available during system peak. Resources with firm peak capacity can be reliably turned on (or "dispatched") up to their full capacity in order to meet load. A battery storage system is an example of this.

As we will discuss in the remainder of the report, we find it reasonable that reliability constraints can be resolved, partially or wholly, through lower peak load. Reliability constraints can be fully resolved through increased capacity via local battery and solar PV resources connected to the distribution or transmission system in the NHRLA. Notably, the NHRLA no longer has either of the Yorktown coal units, which were large, centralized, and inflexible. In contrast, any new battery resources required would be of a modular nature and would not impose a lumpy (i.e., on the order of 160 MW, or the size of a Yorktown coal unit) generation contingency constraint on the system. In other words, new battery resources could be scaled in increments of nearly any size to precisely meet reasonably projected needs including reliability.

2.2. Resource adequacy and needs

In this section, we evaluate a range of possible future load requirements and resource needs for the NHRLA, including an "extreme" case using what we believe are overly conservative estimates of a local capacity need to ensure reliable operations. Using data provided by Dominion and PJM, we find that without the Project, between 2021 and 2030,[29] the region would likely have between 83 MW of surplus capacity and a shortfall of 77 MW of capacity. We also evaluate an extremely conservative scenario in which the NHRLA faces a capacity shortfall of 250 MW. The range encompassed by our results reflects Dominion's lack of clarity and transparency about how system needs have changed as fossil resources are retired, renewables have come online, and Dominion's load growth projections have not materialized. This range also reflects Dominion's failure to analyze smaller modular battery resources as a local supply source. Battery storage can be better matched with low load growth levels and would result in smaller contingency capacity requirements to back up the resource.

We review existing infrastructure in the region and identify the resource capacity needed between now and 2030 to meet area load under extreme weather conditions *without the Project*, all while complying with NERC reliability standards (based on an assessment of NERC-compliant conditions indicated by Dominion prior to Yorktown coal units' retirement). Our assessment of resource needs builds on the load analysis we perform in Section 2.1 using recent historical load data to revise Dominion's stated capacity requirements. Figure 5 summarizes the results of our assessment of Dominion's resource needs in the context of Dominion's load forecast, historical demand, and likely future demand.

In Figure 5 we display three sets of data:

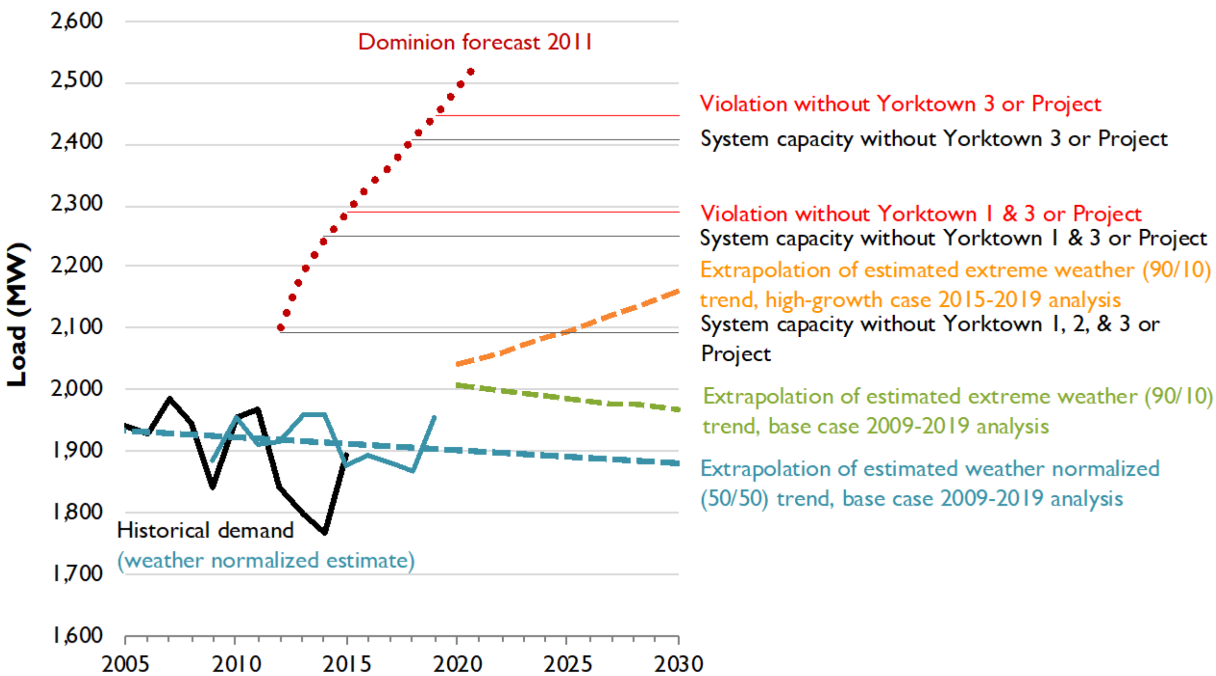
1. First, we show historical load and load forecasts in the NHRLA: (i) actual historical load; (ii) Synapse's estimated historical weather-normalized load based on load in the Dominion Zone; and (iii) Dominion's load forecast from 2011.

[29] We bound our analysis by 2030 in line with standard IRP practices that focus on the next 10–15 years. With slow or no load growth in the NHRLA and rapidly changing system conditions, resource planning should focus on modular and incremental resources that can be built as needed, rather than large centralized resources that are built all at once and cannot be downsized or reduced if/when Dominion's projection of load growth does not materialize.

2. Next, we show Synapse's estimate of future demand in the NHRLA based on the trend in historical demand: (i) future weather-normalized load assuming base load decline; (ii) future extreme weather load with base load decline; and (iii) future extreme weather load with high load growth.

3. Finally, we overlay onto the load forecasts a set of threshold system capacities that show the level of load that can be met with and without various combinations of the three Yorktown units and the Project. Our identification of load levels is based on Dominion's 2012 Application to the SCC, which relied on the company's 2011 load forecast. In Figure 5, if a load line falls below the threshold capacity, we project system resource capacity will exceed load. If a load line falls above the threshold capacity, we project future load will exceed system resource capacity.

Figure 5: Load analysis–Extrapolated NHRLA loads compared to reliable system capacities without Dominion's 500kV project



This figure identifies the reliable threshold system capacities without the Project (with and without Yorktown units) and compares these system capacities to Synapse's estimates of future demand in the NHRLA. The only case in which additional system capacity is required by 2030 is under high-growth with extreme weather if Yorktown Units 1, 2 and 3 are unavailable.
Data sources: Virginia Electric and Power Company. Application of Virginia Electric and Power Company for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, Skiffes Creek 500 kV-230 kV-115 kV Switching Station; Application No. 257. 2012.
PJM Resource Adequacy Planning Department. 2009-2019. PJM Load Forecast Reports, January 2010-2020. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/prev-load-reports.aspx and https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx.

Case 1: Load analysis, base case

We rely on power flow modeling from Dominion's 2012 project application to the SCC to develop our baseline load level. We recognize that SCC staff criticized Dominion's power flow modeling in its application for two issues: (1) inconsistencies with how Dominion defined and conducted contingency studies; and (2) exclusion of additional transmission upgrades that Dominion planned to be in service by June 1, 2016 with this power flow modeling.[30]

In response to the staff critiques, the hearing examiner required Dominion to complete additional power flow modeling to address these and other concerns.[31] However, the company's updated modeling did not provide clear information on the generation-only capacity limits that Dominion believed the system would face without the Project.[32] In light of this, we rely on the 2012 application, which has the most recent, clear and transparent information on system capacity limits, for our base case. The issues outlined by SCC staff regarding Dominion's original modeling indicate that Dominion likely overstated its future need in its application. However, these issues simply mean our analysis is overly conservative, and they do not invalidate the original power flow modeling as the basis for our resource needs analysis.

As shown in Table 2, we start with known levels of baseline load that can be met with existing infrastructure (without the Project) under contingency conditions. Adjusted for plant retirements, this baseline load level is at least 2,092 MW (Row E). We come to this baseline load level of 2,092 MW through several steps outlined below.

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[30] Prefiled testimony of SCC Staff Witness Chiles. SCC, Case No. PUR-2012-00029. Page 7.

[31] Motion of Virginia Electric and Power Company for leave to extend procedural schedule in order to conduct studies requested by staff and request for expedited treatment. January 2013. SCC, Case No. PUE-2012-00029.

[32] We discuss our concerns with the Company's generation alternatives analysis in Case 3.

Table 2: Load analysis to estimate the capacity requirements to avoid reliability concerns in the NHRLA without Dominion's 500kV project

Ref.	Parameter	Source	Power [ratio]
	Base case *without the Project* (trend using 2009-2019 historical data)		
A	2018 reliable system capacity: Summer 2018 peak load forecast	Dominion 2011 forecast	2,407 MW
B	Retirement of Yorktown 1	Dominion 2011 forecast	-159 MW
C=A+B	2018 reliable system capacity without Yorktown 1	Calculated	2,248 MW
D	Retirement of Yorktown 2	Dominion 2012 application to SCC	-156 MW
E=C+D	2022 reliable system capacity without Yorktown 1, and 2 (and Yorktown 3)	Calculated	2,092 MW
F	Max summer peak load, 2020–2030	Forecast of historical load (2009-2019 data)	1,902 MW
G	Summer extreme weather peak load ratio (90/10) in max load year	PJM 2020 forecast	[1.056]
H=F×G	Max summer extreme weather peak load, 2020–2030	Calculated	2,009 MW
I=E-H	*Excess* capacity relative to infrastructure needed to avoid reliability issues	Calculated	83 MW

1. First, we find that in Dominion's 2012 application for the Project, Dominion noted that while the Surry-Skiffes Creek project was originally estimated to be needed in the summer of 2019, the earlier retirement dates for Yorktown Unit 1 and two Chesapeake units outside the NHRLA created a need to accelerate the Project from Summer 2019 to Summer 2015.[33]

   From this statement we infer that without the retirement of Yorktown Unit 1, the existing transmission and NHRLA generation infrastructure was capable of meeting the forecasted NHRLA load during the years prior to 2019 without NERC violations. Specifically, the 2018 expected infrastructure can meet an estimated 2,248 MW of load (Row C) without the Project under contingency planning conditions: Dominion's 2011 peak load forecast for the NHRLA load in Summer 2018 of 2,407 MW (Row A) less the available 159 MW summer capacity of Yorktown Unit 1 Row B).[34]

2. Second, we identify any other infrastructure changes planned in the NHRLA before 2018 as outlined in the application and find that Yorktown Unit 2, with 156 MW summer

[33] Dominion Application. SCC, Case No. PUE-2012-00029. June 2012. Appendix, page 3.

[34] *Id*. Appendix, pages 3 and 22. This is also summarized in the Prefiled testimony of SCC Staff witness Chiles. SCC, PUE-2012-00029. Page 7.

capacity (Row D), is also scheduled to retire.[35] This suggests roughly 2,092 MW of load (Row E) can be met in the NHRLA currently without NERC violations and still without the Project.

Further, we know that when Dominion modeled the years after the retirement of Yorktown 1 and 2 in its 2012 application, under the company's critical system condition planning criteria, the 838 MW Yorktown Unit 3 is not in service.[36] Therefore, Dominion's power flow modeling that showed that existing transmission and NHRLA generation infrastructure was capable of meeting the forecasted NHRLA load during the years prior to 2019 without a NERC violation would have had to have been conducted assuming Yorktown Unit 3 was not in service.

3. Next, we estimate regional load through 2030 (using an extreme weather scenario to be conservative) based on historical load data and load growth rates from 2009 to 2019. As presented in Figure 5 (turquoise dashed line), estimated load in the NHRLA is around 1,902 MW (Row F) in 2020 and trending downward based in part on efficiency measures at government and military buildings served by Dominion[37] and the installation of 38 MW of solar PV at Naval Air Station Oceana in Virginia Beach.[38] Based on our analysis and estimates, this level of load is significantly below the existing capacity of infrastructure serving the NHRLA without the Project (2,248 MW).

   However, to ensure adequate resources exist to meet load in an extreme weather event, we use the "90/10" load forecast to simulate an unexpected but possible increase in demand. In the case of Dominion, the summer extreme weather peak load is between 4.6 percent and 5.6 percent greater than the "50/50" base forecast through 2030.[39] We depict this simulated effect of summer extreme weather in the green dashed line in Figure 5. This would equate to a

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[35] PJM Generation Deactivations. Accessed March 4, 2020. Available at: https://www.pjm.com/planning/services-requests/gen-deactivations.aspx.

[36] Dominion Application. SCC, Case No. PUE-2012-00029. June 2012. Page 19.

[37] See, for example, Statement of Honorable Lucian Niemeyer, Assistant Secretary Of Defense (Energy, Installations and Environment), Before the House Committee on Armed Services Subcommittee on Readiness, Fiscal Year 2019, Department of Defense Budget Request for Energy, Installations and Environment. April 18, 2019. Available at https://www.acq.osd.mil/EIE/Downloads/Testimony/FY19%20EI&E%20Posture%20Statement%20-%20HASC-R.pdf. Also, Office of the Assistant Secretary of Defense for Energy, Installations, and Environment Department of Defense Annual Energy Management and Resilience Report (AEMRR) Fiscal Year 2017. July 2018. Available at https://www.acq.osd.mil/EIE/Downloads/IE/FY%202017%20AEMR.pdf.

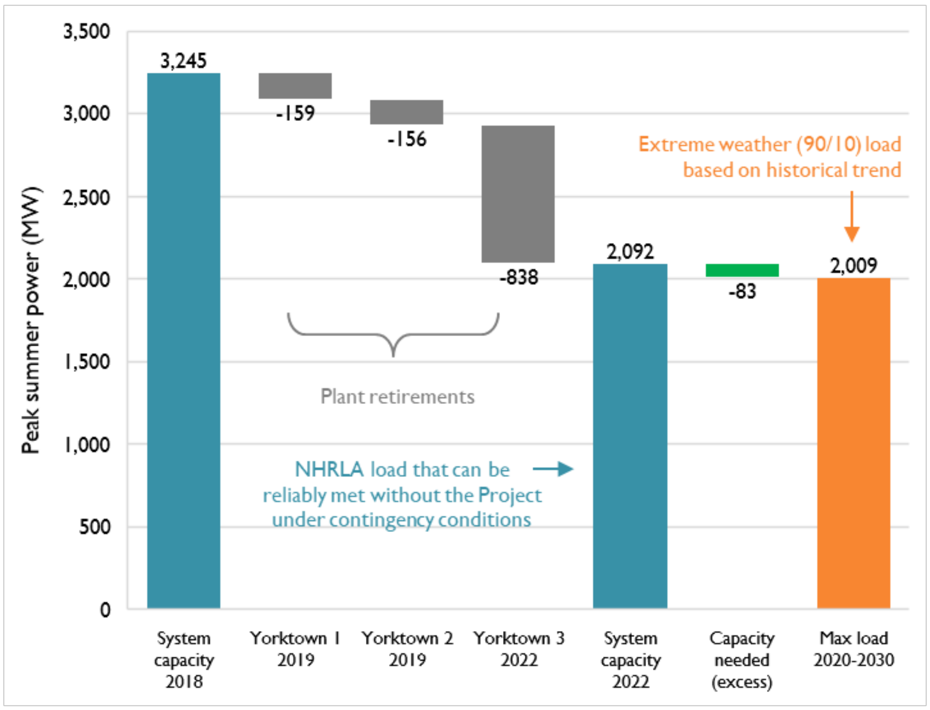
[38] Oceana Solar Facility, Dominion Energy. Available at https://www.dominionenergy.com/company/making-energy/renewable-generation/solar-generation/virginia-solar-projects/oceana, accessed May 6, 2020.

[39] Both the 90/10 and 50/50 load forecasts are developed by PJM based on a simulation that produces a distribution of multiple forecasts. The median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands. As with any forecast or statistical analysis, the choice of inputs and model parameters influences results. We have not reviewed PJM's weather-normalization methodology in detail. See PJM Manual 19, *Load Forecasting and Analysis*. Prepared by Resource Adequacy Planning, December 1, 2017, for more information.

maximum summer extreme weather peak load in the NHRLA of 2,009 MW (Row H) during the period 2020–2030 (1,902 MW x 105.6 percent).

We compare the capacity of the existing infrastructure to estimated maximum load through 2030 and we find that, contrary to what Dominion has been asserting, the system is likely to face minimal reliability constraints over the next decade. In fact, the NHRLA infrastructure has an excess capacity of 83 MW (Row I).[40] In this case, no new infrastructure is required. Figure 6 depicts this result.

Figure 6: Capacity requirements to avoid reliability concerns in the NHRLA without Dominion's 500 kV project, load analysis base case (trend using 2009–2010 historical data)



Given declining demand, Dominion can meet peak demand and NERC requirements in the NHRLA, even in extreme weather events and after retiring Yorktown Units 1, 2, and 3. We estimate Dominion will have a minimum 83 MW of excess capacity between 2020 and 2030.

Case 2: Load analysis, high-growth case

We perform a sensitivity analysis on Case 1, assuming a high load growth rate through 2030 as shown in Table 3. We estimate a new maximum extreme weather load through 2030 of 2,159 MW, based on

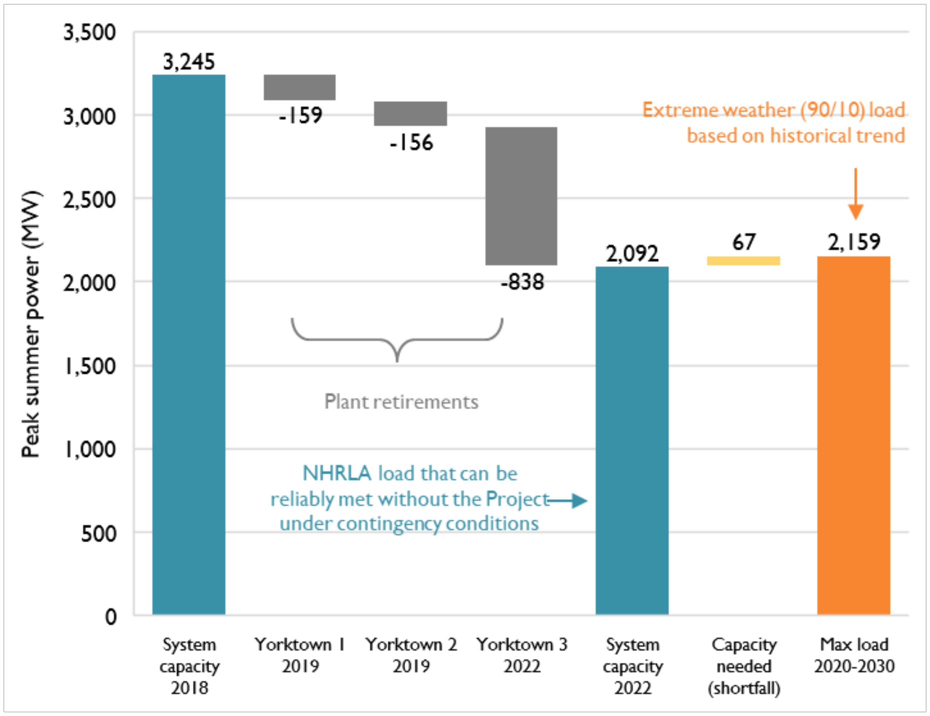
[40] Prior third-party analysis also found that the current system has minimal reliability constraints in the [then] near term. Specifically, a 2016 report prepared by the Princeton Energy Resources International and NPCA noted that "in the near term (one to five years), there appears to be no operational crisis or threat of load shedding on the peninsula because peak loads now are being managed without Yorktown Units 1 and 2 operating." National Parks Conservation Association and Princeton Energy Resources International. DVP's Proposed "Surry-Skiffes Creek project" – Issues and Alternatives, Addendum Report. February 1, 2016.

historical load data from a smaller window of 2015 to 2019. We increase this value by 4.7 percent to 2,159 MW to account for the "90/10" extreme weather peak in 2030, consistent with PJM's 2020 extreme weather estimate for that year. We find that with higher future load growth, the NHRLA could face a shortfall of 67 MW of capacity by year 2030. Under our sensitivity analysis where we assume high load growth in the NHRLA, Dominion would require an additional 67 MW of capacity to meet peak demand and NERC reliability requirements during an extreme weather event and after retiring Yorktown Units 1, 2, and 3. The results are depicted in Figure 7.

Table 3: Load analysis sensitivity to estimate the capacity requirements to avoid reliability concerns in the NHRLA without Dominion's 500kV project

Ref.	Parameter	Source	Power [ratio]
Sensitivity *without the project*: growth scenario (trend using 2015-2019 historical data)			
A	2018 reliable system capacity: Summer 2018 peak load forecast	Dominion 2011 forecast	2,407 MW
B	Retirement of Yorktown 1	Dominion 2011 forecast	-159 MW
C=A+B	2018 reliable system capacity with Yorktown 1	Calculated	2,248 MW
D	Retirement of Yorktown 1, 2	Dominion 2012 application to SCC	-156 MW
E=C+D	2022 reliable system capacity without Yorktown 1, 2, and 3	Calculated	2,092 MW
F'	Max summer peak load, 2020–2030	Forecast of historical load (2015-2019 data)	2,062 MW
G'	Summer extreme weather peak load ratio (90/10) in max load year	PJM 2020 forecast	[1.047]
H'=F'×G'	Max summer extreme weather peak load	Calculated	2,159 MW
I'=H'-E	*Additional* capacity needed to avoid reliability issues	Calculated	67 MW

Figure 7: Capacity requirements to avoid reliability concerns in the NHRLA without Dominion's 500kV project, load analysis <u>high-growth case</u> (trend using 2015-2019 historical data)



Under our sensitivity analysis where we assume high load growth in the NHRLA, Dominion would require an additional 67 MW of capacity to meet peak demand and NERC reliability requirements during an extreme weather event and after retiring Yorktown Units 1, 2, and 3.

Case 3: Capacity need analysis, base case

We do not have full transparency into Dominion's 2013 application updates, however we thought it was important to run a scenario based on numbers the company provided in its 2013 update. Specifically, we started with Dominion's stated capacity need under the generation-only alternative scenario that Dominion evaluated at the order of the hearing examiner in 2013.[41] In this alternative scenario, Dominion assumed that new generation resources in the NHRLA were constructed as an alternative to the Project. We begin with the capacity increase requirement of 295 MW by Year 2019 that Dominion identifies in the Rebuttal testimony of Peter Nedwick[42] as the minimum size of a generating unit that must remain in service to meet load under contingency conditions in the NHRLA on a forward-going

[41] On January 10, 2013, a public hearing was held on the project application. The hearing examiner directed the Company to investigate a series of alternative scenarios including a generation only scenario. Dominion was directed to use the 2013 PJM load forecast, include retirements of Yorktown 1 and 2 and all 4 Chesapeake units, and assume Yorktown 3 was offline.

[42] Rebuttal testimony of P. Nedwick. SCC, Case No. PUE-2012-0029. Page 11.

basis (assuming Yorktown Units 1 and 2 were retired, and Unit 3 was unavailable, and the Project was not built).

Next, we compare Dominion's load forecast for Year 2019 (based on Dominion's 2013 analysis) to Dominion's actual 2019 load. We estimate the NHRLA portion of Dominion's total load was approximately 256 MW lower than forecasted (based on our estimation that NHRLA's accounts for 9.9 percent of Dominion total load). We adjust for the 2 MW difference between the estimated 2019 NHRLA load and the maximum load during the period from 2020 to 2030, which would occur in Year 2020 in our base case trend.[43] Subtracting the shortfall in load from Dominion's generation-only capacity requirement, we find that the current, forward-going capacity requirement in the NHRLA is only 37 MW.

We find that if the capacity need were met with battery storage systems (see discussion in Section 4.2), the backup contingency requirement during system critical conditions could be much smaller, as battery systems can be constructed modularly, that is, in scalable increments. The new contingency requirement would be as large as the individual battery systems,[44] approximately 40 MW. Thus, we estimate a total capacity requirement of 77 MW, adding the 37 MW capacity requirement and the 40 MW contingency requirement. Figure 8 depicts this result.

It is important to note that despite identifying 295 MW as the minimum size of a generating unit that must remain in service in a contingency scenario, Dominion stated that the system requires 620 MW in 2015 and another 618 MW in 2021 to meet system need.[45] To meet this need, Dominion assumed that it will have to spend $633 million retrofitting and repowering Yorktown 1, 2, and 3, and then it will need to build a new gas-fired plant and firm gas transportation infrastructure on the Peninsula to meet 2021 load. The total cost for these two projects was projected to be $1.345 billion.[46] Renewables and distributed generation resources were not adequately considered,[47] and no consideration was given to the capabilities of battery resources to contribute to local supply needs.

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[43] For our base estimate (Case 1), we estimate future load in the NHRLA will decline at a rate of 2 MW per year.

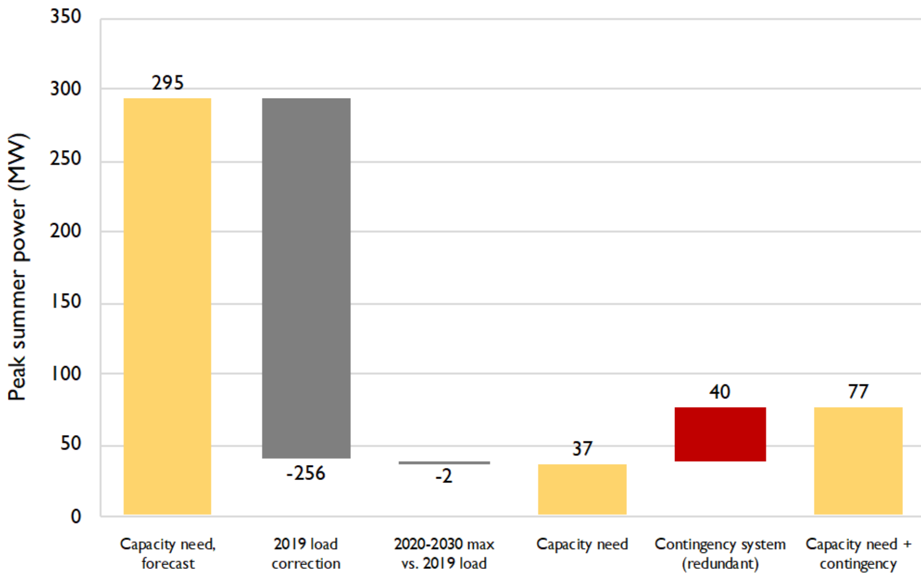
[44] This assumes the battery storage systems are designed and located in a systematic manner to prevent simultaneous failure of multiple systems.

[45] Rebuttal testimony of G. Kelly. SCC, Case No. PUE-2012-0029. Rebuttal Schedule 3, page 3 of 9. Dominion provides no transparency into the basis of its assertion that the region will have a 620 MW capacity need in 2015 and an additional 618 MW need in 2021.

[46] *Id,* page 22.

[47] Dominion stated that resources such as biomass, wind, and solar were not sited in this region on the basis of their relative cost and site availability. Dominion made no mention of battery storage. Rebuttal testimony of G. Kelly. SCC, Case No. PUE-2012-0029. Page 16.

Figure 8: Capacity requirements to avoid reliability concerns in the NHRLA without Dominion's 500kV project, capacity need analysis base case



Case 4: Conservative high capacity need

We define a Case 4 in the interests of testing the costs of a conservative solution that exceeds needs. This case assumes that the overall reliable import capacity into the NHRLA after an extreme contingency is equal to the maximum peak load we consider (Case 2), less 250 MW (2,159 – 250 =1,909 MW). Based on the material in Dominion's analyses,[48] it is reasonable to assume that a stressed transmission system could reliably serve a transmission system peak load (net of internal NHRLA supply of 250 MW) of at least 1,909 MW without violating NERC requirements.

2.3. New resources and infrastructure to meet transmission security requirements

Section 2.2 above describes how we estimate that the current infrastructure in the NHRLA is adequate (or at the most conservative, requires only small incremental investments) to meet the estimated extreme weather load over the next decade. However, it is possible that changes in load, generation, and transmission could either increase or decrease this margin of excess capacity. Should such changes occur, new resource projects or demand-side management programs[49] could be developed to provide

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[48] See, for example, rebuttal testimony of P. Nedwick. SCC, Case No. PUE-2012-0029.

[49] Demand-side management programs consist of the planning, implementing, and monitoring activities of electric utilities which are designed to encourage consumers to modify their level and pattern of electricity usage. More information from the U.S. Energy Information Administration is available at https://www.eia.gov/electricity/data/eia861/dsm/.

local power and reliability services similar to those delivered by Yorktown Units 1 and 2 prior to retirement.

New supply-side and demand-side resources, to the extent that each can provide power or reduce demand within the NHRLA during times of peak load, would reduce the need to import energy into the NHRLA.[50] Supply resources could include new utility-scale or distributed solar power systems, wind farms, battery energy storage, or conventional fossil-fired power plants. Available demand-side resources include energy efficiency, demand response, and behind-the-meter solar photovoltaics and batteries. Both supply- and demand-side alternatives can be paired with transmission solutions that do not involve building a large transmission line across a scenic river crossing to ensure reliability.

Dominion is currently developing a new offshore wind project that will serve the region. The Coastal Virginia Offshore Wind project is a 12 MW pilot farm currently under construction, expected to begin delivering power in late 2020.[51] The project will interconnect in the SHRLA. Dominion is also in the beginning stage of developing an additional 2,600 MW of wind power off the coast of Virginia near Virginia Beach, intended to be available by 2026.[52] This project is planned to interconnect in the City of Chesapeake (in the SHRLA). While these projects will not reduce transmission constraints into the NHRLA, when completed they will aid in balancing the transmission system in the coastal region of southeastern Virginia, which is expected to improve overall system reliability. Because the SHRLA and NHRLA are electrically interconnected, these projects will also increase the availability of electricity for import into the NHRLA from the south.

There is also potential for development of additional projects in the NHRLA by merchant plant owners. An example of this is a 1,100 MW natural gas-fired combined cycle plant which received a permit in Charles City County in 2016. In March 2019, the permit holder C4GT was granted an extension of its sunset provision, giving C4GT until May 2021 to begin actively developing the project. At this time, the company claimed that the project is still viable but cited “an unexpected change in the market for electric generating capacity” as cause for delay.[53] Despite this clear evidence that demand in NHRLA is

[50] The following factual discussion of proposed supply resources is not intended to indicate support for any particular project.

[51] Dominion Energy. Coastal Virginia Offshore Wind. Accessed 3/4/2020. Available at: https://www.dominionenergy.com/company/making-energy/renewable-generation/wind/coastal-virginia-offshore-wind.

[52] The Washington Post. Dominion Energy plans major offshore wind farm near Virginia Beach. Accessed 3/4/2020. Available at: https://www.washingtonpost.com/local/virginia-politics/dominion-energy-plans-major-offshore-wind-farm-near-virginia-beach/2019/09/19/7d76f6d2-daf9-11e9-a688-303693fb4b0b_story.html.

[53] Application of C4GT, LLC to the State Corporation Commission for certification of an electric generating facility in Charles City County. March 12, 2019. SCC, PUE-2016-00104.

not adequate to support a new plant, in the end of 2019 Virginia Natural Gas applied to the SCC to undertake a new pipeline project to serve the C4GT plant.[54]

3. THE SURRY-SKIFFES CREEK 500 KV TRANSMISSION LINE

3.1. Project description and specifications

In this section, we summarize the cost and operational characteristics of the Project.

The Surry-Skiffes 500 kV transmission line #582 is approximately 7.4 miles in length and crosses the James River to connect the previously existing 500 kV–230 kV Surry Switching Station in James City County to a newly constructed 230 kV–115 kV Skiffes Creek Switching Station also in James City County. The overall project—which includes the Surry-Skiffes Creek transmission line, the Skiffes Creek-Whealton transmission line, and the Skiffes Creek switching station—was estimated to cost $150.6 million (2011 dollars) to construct, require 12 months for planning-related activities, and require 18 months for construction.[55] The actual project cost is $443.5 million (2019 dollars) to date including $348 million for construction and $95.5 million for environmental mitigation.[56]

3.2. Prior analysis of alternatives to the Surry-Skiffes line

An environmental impact statement (EIS) is a planning document required under the National Environmental Policy Act (NEPA) for certain federal actions, such as major construction projects, that significantly affect the environment. An EIS identifies positive and negative environmental effects of the proposed action and lists alternative actions for consideration. The Army Corps failed to prepare a full EIS prior to issuing the permit to Dominion for construction of the Project. In *National Parks Conservation Association* v. *Semonite*, the U.S. Court of Appeals for the District of Columbia Circuit instructed the Army Corps to prepare an EIS.

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[54] On December 6, 2019 Virginia Natural Gas (“VNG”) filed a request for SCC approval to undertake $345 million in new infrastructure projects. The capital projects include new compressor stations and approximately 25 miles of pipeline facilities. VNG states that the infrastructure projects are necessary to serve a planned 1,040 MW combined cycle gas facility in Charles City County being constructed by an independent power producer, C4GT, LLC. VNG states that 94 percent of the infrastructure costs will be borne by C4GT, LLC.

[55] Dominion Application. SCC, Case No. PUE-2012-00029. June 2012. Pages 6 and 7.

[56] Project cost update provided by Dominion during a virtual stakeholder meeting convened by the USACE on April 23, 2020. David DePippo, an attorney for Dominion Energy, stated that Dominion had sent the Corps a letter stating that the actual costs of the Surry-Skiffes Creek project totaled $443.5 million: $348 million construction plus $95.5 million for mitigation.

Dominion's alternatives analysis

Dominion noted in its 2012 application to the SCC for construction of the Project that "[t]he proposed facilities will afford the best means of meeting the continuing need for reliable service while reasonably minimizing adverse impact on the scenic, environmental and historical assets of the area."[57] The assertion that the Project is the "best means" implies that Dominion evaluated all reasonable alternatives to the Project and determined the proposed infrastructure to be the least costly practicable option. The project record, however, shows that in its initial application, Dominion only presents a portfolio of three variations of how the Project would cross the James River and one alternate transmission route.[58] Subsequently, Dominion was required by the hearing examiner to produce a series of additional alternative scenarios.[59] However, as discussed above, Dominion relied on inflated demand forecasts for all scenarios, and failed to conduct an adequate appraisal of alternative supply-side and demand-side resources, including battery storage.[60]

The Army Corps' alternatives analysis

The Army Corps also evaluated alternatives to the Project but found that the Project was the least costly way to meet Dominion's purported need in the NHRLA. At the time of the Army Corps' evaluation of alternatives, Dominion estimated the Project would cost $180 million (2015 dollars).[61] The Army Corps did not question Dominion's stated need for the Oroject. Additionally, the Army Corps, Dominion and PJM evaluated the alternatives proposed by Tabors.[62]

Tabors' alternatives analysis

The National Trust for Historic Preservation retained the firm of Tabors Caramanis Rudkevich (Tabors) to identify alternatives to the Project that would not require an overhead crossing of the James River and would meet all relevant planning and reliability criteria.[63] Tabors identified

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57 Dominion Application. SCC, Case No. PUE-2012-00029. June 2012. Page 7.

58 *Id*. Appendix, pages 55 – 61.

59 See, for example, Motion of Virginia Electric and Power Company for leave to extend procedural schedule in order to conduct studies requested by staff and request for expedited treatment. SCC, Case No. PUE-2012-00029.

60 Rebuttal testimony of P. Nedwick. SCC, Case No. PUE-2012-00029 and Rebuttal testimony of G. Kelly. SCC, Case No. PUE-2012-00029.

61 USACE Preliminary Alternatives Conclusions White Paper RE: NAO-2012-0080 / 13-V0408. October 1, 2015.

62 See, for example Surry-Skiffes Creek – Whealton: Modeling Review of NTHP/Tabors Alternatives. Dominion Energy, November 17, 2016.

63 Tabors, Richard. *Alternatives to Surry-Skiffes Creek 500 kV Overhead Project.* Tabors Caramanis Rudkevich. October 2016. Available at https://nthp-savingplaces.s3.amazonaws.com/2017/02/14/10/27/11/381/NTHP-TCR%20Alternatives%20Report%20(002).pdf.

a series of alternative options in its October 2016 report that included both alternative transmission solutions and reconfiguration or modifications of existing resources and assets.

Dominion's and the Army Corps' response to alternatives analysis

Dominion and the Army Corps had two main criticisms of the external analysis, which they asserted repeatedly in what appears to be an attempt to discredit all third-party analyses. The Army Corps claims that "peak load, while relevant, is not the only applicable criteria that must be considered. Power flow modeling studies must be conducted to evaluate whether an alternative meets NERC Reliability Standards at all points in the system under all contingencies."[64]

While it is true that any resource portfolio would need to be operationally validated by power flow modeling, this holds true for <u>all</u> resource planning exercises, whether they are completed by using production cost and capacity expansion modeling or simple spreadsheet analysis. Instead, this statement incorrectly conflates the need to validate and verify proposed solutions with power flow modeling with the inability to identify alternatives that are likely to meet system needs. Tabors conducted power flow modeling using transmission planning information that Dominion submitted to the Federal Energy Regulatory Commission (FERC);[65] however, Dominion discounted even this analysis as inadequate, relying on Dominion's assertion that the FERC data did not contain the system's most current topology (system mapping), among other things. Once again, Dominion completely discounted external analysis that did not match its own results rather than seriously evaluating whether the proposed alternatives could provide least-cost solutions.

4. Local Area Supply and Demand-Side Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line

In this section, we analyze and present alternative options to the Project. It is important to note that the alternative resource portfolios we discuss are not intended to provide a one-for-one replacement of the Project. Instead, we evaluate what the NHRLA electricity system needs (energy, capacity, and grid services) in the absence of the Project and design resource portfolios that can meet those needs. The alternatives we consider can provide a range of services—capacity, energy, voltage support, fast start, ramping, avoided capacity, and avoided energy—which are different than the transmission services provided by the Project.

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[64] Surry-Skiffes Creek Whealton Modeling and Alternatives Analysis Review, US Army Corps of Engineers. February 11, 2016.

[65] FERC is the federal agency that regulates, among other things, the transmission and wholesale sale of electricity and natural gas in interstate commerce.

4.1. Resource portfolio considerations

In designing alternative resource portfolios,[66] we focused on resource portfolios that met three main criteria:

1. Resource portfolio would meet or exceed the contingency planning requirements without NERC violations.
2. Resource portfolio would not increase environmental impact through new fossil fuel-based generation that creates greenhouse gas emissions and local air pollution (we did not consider bringing Yorktown Units 1 or 2 back online) and would support the future build-out of renewables and investment in energy efficiency.
3. Resource portfolio would meet the energy, capacity, and grid services needs for the NHRLA in the absence of the Project.

4.2. Alternative resource options

In this section, we discuss resource portfolio considerations, review the alternative resource options that we evaluated, and present the costs and operational services provided by several alternatives that can meet the systems needs with resources in the load area.

Our recommendations are aligned with recent state laws and executive orders, which order Dominion to ramp up investments in renewables and in energy efficiency:

1. First, in 2018, Virginia enacted Senate Bill 966, the Grid Transformation and Security Act, which requires Dominion[67] to build 5,000 MW of utility-operated solar and wind resources by 2028 and to spend $870 million on efficiency programs between 2018 and 2027.
2. Then, in September 2019, Governor Ralph Northam signed Executive Order Number 43, calling for 30 percent of Virginia's electricity to come from renewables by 2030 and to be carbon-free by 2050.[68]
3. Most recently, in April 2020, Governor Northam signed into law the Virginia Clean Economy Act. This statute replaces the state's voluntary renewable portfolio standards and "requires the state's biggest utilities to deliver electricity from 100 percent renewable sources by 2045, sets a timeline for closing old fossil fuel plants and

[66] A resource portfolio is a combination of supply- and demand-side resources that together provide the capacity, energy, and grid services needed to meet system needs. Our resource portfolios include battery storage, solar PV (both supply-side resources), and energy efficiency (a "demand-side" resource).

[67] Senate Bill 966 places requirements on Appalachian Power Company, as well.

[68] Commonwealth of Virginia, Office of the Governor. 2019. Executive Order Number 43. Available at: https://www.governor.virginia.gov/media/governorvirginiagov/executive-actions/EO-43-Expanding-Access-to-Clean-Energy-and-Growing-the-Clean-Energy-Jobs-of-the-Future.pdf.

mandates gains in energy efficiency."[69] The Act requires utilities to own and operate up to 5 GW of offshore wind and requires Dominion to deploy 2.7 GW of energy storage by 2035.[70]

Battery storage

Battery storage, either stand-alone or paired with solar, can by deployed in the NHRLA to provide local operating reserve for contingency events, voltage support, and peak load operation to reduce transmission loads at critical hours.

Batteries can store energy that is either produced in the NHRLA in off-peak hours, or imported over existing transmission infrastructure during off-peak times, for use as contingency reserve and also during high demand on-peak hours as required. Batteries can be deployed at different scales, depending on need, and can offer co-benefits beyond just firm capacity, including resilience, including:

- as a utility-scale, utility or third-party owned resource connected at the transmission level (e.g., connected at the Yorktown station);
- as a utility or third-party owned distributed resource at lower voltages (sub-transmission or distribution system voltages); or
- at the customer scale, behind or in front of meters[71] depending on the customer size and the specific service characteristics at that customer site.

In any of these configurations, utility control of the battery resource could be established as required. Batteries are also available in multiple capacity-to-energy configurations depending on whether the system needs just one hour of peaking capacity, or a longer four- to eight-hour duration capacity and energy resources.

The battery storage alternatives we consider include 2-hour and 4-hour duration options,[72] though our estimate of costs assume a 4-hour battery as a component of the resource solution. Determining the required duration for capacity from batteries that are providing primarily contingency reserve response is a complex exercise, and we do not attempt to optimize the duration required for the battery

[69] Schneider, Gregory. "Virginia passes sweeping law to mandate clean energy amid question about cost." *The Washington Post*, March 6, 2020. Available at https://www.washingtonpost.com/local/virginia-politics/virginia-dominion-energy-bill/2020/03/06/4524cd20-5fc1-11ea-b29b-9db42f7803a7_story.html.

[70] Gheorghiu, Iulia. "Clean energy bill marks dramatic transition for Virginia amid dispute over costs to customers." *Utility Dive*, March 10, 2010. Available at https://www.utilitydive.com/news/clean-energy-bill-marks-dramatic-transition-for-virginia-amid-dispute-over/573793/.

[71] Behind-the-meter battery systems are connected on the customer side of the electricity meter (literally behind the meter). On the other hand, grid-connected systems are connected directly to the electricity distribution or transmission system.

[72] See Table 4 for cost comparison of 4-hour and 8-hour battery storage resources.

resources. For a number of contingent events, a lower duration requirement could suffice; for certain extreme events, a longer-duration battery would be reasonable.

While battery storage was historically not competitive with traditional fossil peaking resources in all contexts, costs have dropped dramatically (50 percent over the past five years)[73] and are projected to continue to do so for the foreseeable future. With a large mandate from the state to invest in renewables and battery storage, a sizable portion of those requirements can be installed in the NHRLA, by or on behalf of Dominion, thus providing the co-benefit of meeting part of the requirements while also allowing reliable operation through provision of capacity and ancillary services.

Demand-side resources

Virginia has historically underinvested in energy efficiency. In 2015, Dominion Virginia Power ranked second to last for energy efficiency programs and policy among the 51 largest U.S. utilities in the American Council for an Energy-Efficient Economy (ACEEE) utility ranking report.[74,75] The company has made little improvement since 2015, and in 2018 ranked 50 out of the 52 utilities reviewed in that year's report.[76] According to experts at ACEEE, as of Spring 2019, Dominion was on track to spend only 40 percent of the $870 million required by 2027 under the Grid Transformation and Security Act.[77] Also, NERC has specifically acknowledged the importance and prevalence of energy efficiency and other demand-side resources reducing peak load throughout U.S. regions.[78]

The Army Corps claimed that energy efficiency and other demand-side management options cannot be used to address NERC reliability concerns, stating that "[Demand-side management] resources are already included in the transmission planning process. Additional amounts cannot be assumed to be available to address NERC reliability violations due to transient and voluntary nature of these

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[73] Lazard Levelized Cost of Energy Version 9.0, November 2015. Lazard Levelized Cost of Energy Version 13.0, November 2019. LCOE and capital cost of Crystalline Utility-Scale Solar PV.

[74] Relf, Grace, Brendon Baaz, and Seth Nowak. *2017 Utility Energy Efficiency Scorecard.* American Council for an Energy-Efficient Economy. June 2017.

[75] ACEEE's 2017 Utility Energy Efficiency Scorecard evaluates utility performance in 2015, and its 2020 Scorecard evaluates utility performance in 2018.

[76] Relf, Grace, Emma Cooper, Rachel Gold, Akanksha Goyal, and Corri Waters. *2020 Utility Energy Efficiency Scorecard.* American Council for an Energy-Efficient Economy. February 2020. Available at https://www.aceee.org/research-report/u2004. We note that the scorecard does not represent a ranking of *all* of the nation's utilities, just the largest.

[77] McGowan, Elizabeth. "Dominion needs to ramp up efficiency programs to hit mandate, advocates say." Energy Efficiency Network. May 2019. Available at https://energynews.us/2019/05/24/us/dominion-needs-to-ramp-up-efficiency-programs-to-hit-mandate-advocates-say/.

78 NERC, 2019 Long-Term Reliability Assessment. "Continued advancements of EE programs combined with a general shift in North America to less energy-intensive economic growth are contributing factors to slower electricity demand growth. Thirty states in the United States have adopted EE policies that are contributing to reduced peak demand and overall energy use.[27] Additionally, DERs and other behind-the meter resources continue to increase and reduce the net demand for the BPS even further." Page 40. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf.

resources."[79] This is simply not accurate, and it reflects a misunderstanding of the manner in which energy efficiency resources help. While not a controllable resource, they do predictably reduce peak demand and thus provide a critical measure of reliability benefit. Demand response and energy efficiency can reduce end-users' coincident peak demand, which is demand at the time that the system is experiencing peak demand.[80] This in turn drives down the peak load which decreases the amount of energy Dominion would need to import into the NHRLA. Further, because energy efficiency is often the lowest-cost resource available, it should always be considered first, or at the very least, be considered as part of a suite of resource options.

Solar photovoltaics

Solar photovoltaics (PV) can provide carbon-free energy in the NHRLA that reduces peak load exposure during the summer months when transmission constraints are likely to be the most restrictive due to thermal constraints. Additionally, when paired (either directly, or indirectly) with battery storage, solar energy can be stored during daytime off-peak hours for use during higher load peak hours (for example, in the late afternoon).

Solar can be deployed at multiple scales, including distributed (behind or in front of the meter), community solar, and utility scale, depending on the size and location of system needs. Solar PV has been rapidly deployed across the country at all scales and is cost competitive with traditional energy resources in most locations. Virginia's neighbor to the south, North Carolina, is a national leader in solar deployment, behind only California,[81] while Virginia ranked 19th nationally in total solar deployment in 2019.[82]

Voltage support

Battery resources controlled by Dominion can directly provide critical grid support services such as voltage support needed to operate the transmission grid. Batteries can instantaneously provide reactive support when needed, due to either contingency events (when one or more generator or transmission asset is unavailable) or to predictable changes in load over the course of the day, if or as necessary.

Crucially, battery resources can serve as contingency reserve in the NHRLA and respond with both *real power injection and reactive power support*, in the event of a contingency. During normal grid operations, even at the highest peak load periods, the transmission system can fully support *energy*

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[79] USACE Preliminary Alternatives Conclusions White Paper RE: NAO-2012-0080 / 13-V0408. October 1, 2015.

[80] Coincident peak demand refers to the demand from a particular user or sub-region at the time that the NHRLA is experiencing peak demand. This is in contrast with non-coincident peak demand, which refers to the peak demand of a specific end-user or region.

[81] Solar Energy Industries Association, North Carolina Data through Q3 2019. Available at https://www.seia.org/state-solar-policy/north-carolina-solar.

[82] Solar Energy Industries Association, Solar State by State. Available at https://www.seia.org/states-map.

requirements without having to rely on a local source of power supply. The locally-sited battery resource, fully charged, would be available to instantly inject power onto the grid under contingency conditions to relieve the pressure on the transmission system to fully supply all requirements when a component or possibly multiple components are out of service.

Voltage support for the NHRLA can also come from non-battery resources. There are several categories of devices that can adjust voltage and provide power factor support, including synchronous condensers or solid-state reactive power support (e.g., Static Var Compensation, SVC), in addition to conventional static capacitance.[83] These devices will ideally provide voltage support in an optimized fashion with any utility-controlled battery resources available in the area.

4.3. Alternative resource portfolio options

In this section, we review and present alternative resource portfolio options to the Project. Each resource portfolio contains a combination of alternative supply and demand-side resources, in varying proportions, which together satisfy the marginal or outstanding resource needs in the NHRLA (assuming current system conditions in the absence of the Project).

We selected resources that provide enough capacity to meet peak system load using conservative assumptions assuming PJM's 90/10 summer load projections. We also designed portfolios to meet two different resource need levels (as discussed in Case 2, Case 3, and Case 4 within Section 2.2).

In Table 4 we show the costs and services provided by the alternative resources that we considered. We considered energy efficiency, battery storage (in two sizes), solar PV, and reactive power support for inclusion in our alternative resource portfolios.

[83] All devices listed here provide a form of either dynamic (i.e., instantaneously responsive) or static (i.e., switched into place by operator action, or automatically) voltage support, allowing the system to remain within acceptable voltage limits. Synchronous condensers are synchronous motors that are configured (with a free-spinning shaft) to generate or absorb reactive power as needed to adjust grid voltage or improve the power factor. Static Var Compensation are electrical devices using solid-state electronic components that provide fast-acting (near instantaneous) reactive power without significant moving parts (except an internal switchgear). Conventional static capacitance refers to simple mechanically switched capacitors that provide reactive power but are not fast-acting like SVCs.

Table 4: Resource options evaluated in alternative portfolio analysis

Alternative resource comparison	Services provided	Installed Cost *2020$/kW*	Installation Year	Economic life *Years*	Time to deploy
Energy efficiency + demand response	Avoided capacity, avoided energy	$1,385	2021	11	< 2 years
Battery storage (2 hr)	Capacity, voltage support, fast start, ramping	$637	2021	20	< 2 years
Battery storage (4 hr)	Capacity, voltage support, fast start, ramping	$1,202	2021	20	< 2 years
Solar photovoltaic	Energy, capacity	$1,112	2021	30	< 2 years
Synchronous condenser or battery storage*	Voltage support (dynamic reactive power)	(included in battery cost)	2021	30	< 2 years
Surry-Skiffes Creek transmission project	Transmission capacity	$443.5 million total project cost	2019	30	

Note: The Surry-Skiffes Creek project's construction costs are $443.5 million to date. Voltage support costs for battery resources are part of the overall costs shown for batteries. Voltage support costs for synchronous condensers vary. A 2014 FERC staff report on reactive power ("Payment for Reactive Power," April 22, 2014, https://www.ferc.gov/legal/staff-reports/2014/04-11-14-reactive-power.pdf) provided two examples of costs for steam plant conversion to synchronous condensing (Huntington Beach in California, and Eastlake in Ohio), indicating costs on the order of $50,000 per MVAR, or (e.g.) $5 million for 100 MVAR of reactive capacity. Specific needs for synchronous condensers or SVCs at Yorktown, e.g., would depend on the extent of voltage support provided by battery resources. We assume voltage support costs are part of the battery resource cost in our alternatives analysis.

In Table 5, Table 6, and Table 7, we present the results of our resource portfolio analysis. Each table assumes a different resource need in Year 2021 to meet load in the NHRLA without the Project: 67 MW, 77 MW, or 250 MW. We present this range of capacities because the actual load requirement is not fully transparent from Dominion's information and analysis. The three capacities match those identified in our resource needs analysis in Case 2, Case 3, and Case 4.[84] We vary the portion of resources used in each portfolio to evaluate how costs vary based on portfolio composition, as there are a number of supply-side and demand-side alternatives for meeting demand in the NHRLA.[85] In Portfolio A, we rely exclusively on battery storage resources; in Portfolio B, we rely on a mix of battery storage, solar PV, and energy efficiency; and in Portfolio C, we rely on a split of solar PV and battery storage.

Table 5 shows the results of our analysis assuming high load growth on the NHRLA as described in Case 2. Table 6 shows our results based on Dominion's need for a minimum unit size of 295 MW as expressed in its generation-only alternatives analysis, adjusted to correct for the difference between actual load and forecasted load growth as in our Case 3 analysis.

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[84] Notably, there is no need for new infrastructure under Case 1, and consequentially there would be no cost. Therefore, the presented tabular results are a conservative subset of our analysis.

[85] All capacities are presented as nameplate capacity. The EIA defines generator nameplate capacity as the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer.

Costs range from $80 million to $516 million, depending on the resource need and the chosen options. We present the costs in Table 7 only in the interest of illustrating a conservative solution that exceeds needs. That is, we expect new resources totaling approximately 70 MW would be sufficient to meet load requirements in the NHRLA over the next decade, and the corresponding costs would likely be in the range of $80 million to $160 million. In all cases, the resource portfolio that relies wholly on battery storage is the least costly option.[86] This is due in part to Dominion's poor historical investment in energy efficiency, and therefore the high cost of the resource based on current company data. It is important to note that energy efficiency program costs are likely to be considerably lower than estimated here when designed correctly.

Table 5: Alternative portfolios assuming 67 MW resource need in 2021

	Option A		Option B		Option C	
Resource shares and capacities	Share %	Capacity MW	Share %	Capacity MW	Share %	Capacity MW
Energy efficiency + demand response	0%	-	25%	17	0%	-
Solar photovoltaic*	0%	-	25%	44	50%	88
Battery storage (4 hr)	100%	67	50%	33	50%	33
Total	**100%**	**67**	**100%**	**94**	**100%**	**121**
System costs	Per unit $/kW	Total 2020$, million	Per unit $/kW	Total 2020$, million	Per unit $/kW	Total 2020$, million
Energy efficiency + demand response	$1,385	$0	$1,385	$23	$1,385	$0
Solar photovoltaic*	$1,112	$0	$1,112	$49	$1,112	$98
Battery storage (4 hr)	$1,202	$80	$1,202	$40	$1,202	$40
Grand total		**$80**		**$112**		**$138**

**Assumes 38 percent of solar nameplate capacity is credited toward peak, per PJM planning requirements.*
Parts may not sum to totals due to rounding.

[86] We have conservatively ignored other net benefits that accrue to both solar PV and demand-side resource components installed in the NHRLA in Options B and C. Those benefits include displacing energy costs that would otherwise arise absent their installation.

Table 6: Alternative portfolios assuming 77 MW resource need in 2021

	Option A		Option B		Option C	
Resource shares and capacities	Share %	Capacity *MW*	Share %	Capacity *MW*	Share %	Capacity *MW*
Energy efficiency + demand response	0%	-	25%	19	0%	-
Solar photovoltaic*	0%	-	25%	51	50%	102
Battery storage (4 hr)	100%	77	50%	39	50%	39
Total	**100%**	**77**	**100%**	**109**	**100%**	**140**
System costs	Per unit *$/kW*	Total *2020$, million*	Per unit *$/kW*	Total *2020$, million*	Per unit *$/kW*	Total *2020$, million*
Energy efficiency + demand response	$1,385	$0	$1,385	$27	$1,385	$0
Solar photovoltaic*	$1,112	$0	$1,112	$57	$1,112	$113
Battery storage (4 hr)	$1,202	$93	$1,202	$46	$1,202	$46
Grand total		**$93**		**$130**		**$160**

**Assumes 38 percent of solar nameplate capacity is credited toward peak, per PJM planning requirements. Parts may not sum to totals due to rounding.*

Table 7: Alternative portfolios assuming 250 MW resource need in 2021

	Option A		Option B		Option C	
Resource shares and capacities	Share %	Capacity *MW*	Share %	Capacity *MW*	Share %	Capacity *MW*
Energy efficiency + demand response	0%	-	25%	63	0%	-
Solar photovoltaic*	0%	-	25%	164	50%	329
Battery storage (4 hr)	100%	250	50%	125	50%	125
Total	**100%**	**250**	**100%**	**352**	**100%**	**454**
System costs	Per unit *$/kW*	Total *2020$, million*	Per unit *$/kW*	Total *2020$, million*	Per unit *$/kW*	Total *2020$, million*
Energy efficiency + demand response	$1,385	$0	$1,385	$87	$1,385	$0
Solar photovoltaic*	$1,112	$0	$1,112	$183	$1,112	$366
Battery storage (4 hr)	$1,202	$301	$1,202	$150	$1,202	$150
Grand total		**$301**		**$420**		**$516**

**Assumes 38 percent of solar nameplate capacity is credited toward peak, per PJM planning requirements.*
Parts may not sum to totals due to rounding.

Option A relies solely on battery storage systems to meet the additional resource needs in the NHRLA. While the Army Corps EIS should optimize for the sizing of the capacity of the battery systems, we assume a 4-hour capacity. That is, we assume the amount of electricity the systems can store is sufficient to provide maximum power output for a 4-hour period.[87] The battery storage systems could be built in modular increments of up to 40 MW and could be interconnected at existing transmission or distribution stations, as shown in the example in Figure 9, or at shuttered generation facilities such as the Yorktown Power Station.

[87] For example, a 36 MW system with 4 hours of capacity would include 144 MWh of storage.

Figure 9: 20 MW battery system with 4-hour storage capacity (80 MWh)

Source: PV Magazine 2018 – Tesla's 20MW/80MWh PowerPack substation in Mira Loma, California

Option B includes 50 percent shares of battery storage plus 25 percent shares of solar PV (at equivalent capacity crediting) and peak reductions from energy efficiency. The cost of solar assumes utility-scale projects, but the actual quantities required could be provided by smaller-scale solar, with downstream benefits offsetting the increased costs of smaller-scale systems. The incremental costs for energy efficiency may very well be minimal, rather than maximum as shown, to the extent that Dominion's requirements to deploy these resources includes deployment across the Peninsula.

Option C includes 50 percent shares of battery storage plus 50 percent shares of solar PV. There are a myriad of combinations of utility-scale and smaller-scale solar that could be considered as a viable solar PV increment across the NHRLA—this report does not attempt to optimize, or incorporate policy provisions, into our assessment of solar PV. In a similar vein, many different combinations of battery storage could be deployed on the Peninsula, both utility-scale and smaller-scale. We do note that it is critically important that Dominion, or PJM, have visibility and possibly direct control of battery resources in order to ensure their availability and provision of required services when needed.

5. CONCLUSION

5.1. Key Findings

First, Dominion's assertion that the Surry-Skiffes Creek-Whealton Project is needed to maintain electric reliability in the NHRLA is not supported by the record.

Second, Dominion systematically over-projected demand to justify building the Project and may have a capacity surplus even without the Project.

Third, Dominion's alternatives analysis failed to consider locally sited battery storage, renewables, and demand-side management.

Fourth, the region's existing transmission network would reliably meet the needs of the NHRLA without Dominion's preferred Surry-Skiffes Creek Project, if combined with other resources. Specifically, these resources include locally sited solar PV, continuing improvements in available, cost-effective peak-load reducing efficiency measures, and—crucially—highly responsive, predictably-dispatchable battery storage resources that also provide critical ancillary services.

5.2. Recommendations

1. The forthcoming EIS process led by the Army Corps should directly evaluate the purpose of and need for the Project.

2. The EIS should evaluate alternatives to the Surry-Skiffes Creek project that include modularly scaled battery storage, solar PV, and peak-load-reducing energy efficiency or demand-response options.

3. The EIS should evaluate any incremental costs associated with required energy efficiency, demand response, solar PV, and battery resources needed to ensure that threshold net load levels seen on the transmission system during summer peak periods across the NHRLA are below those required to ensure compliance with NERC transmission operation standards.

APPENDIX A: ABOUT THE AUTHORS

Synapse Energy Economics is a research and consulting firm specializing in energy, economic, and environmental topics. Since its inception in 1996, Synapse has grown to become a leader in providing rigorous analysis of the electric power sector for public interest and governmental clients.

Synapse's staff of 30+ includes experts in energy and environmental economics, resource planning, electricity dispatch and economic modeling, energy efficiency, renewable energy, energy storage, transportation and building sector electrification, transmission and distribution, rate design and cost allocation, risk management, benefit-cost analysis, environmental compliance, climate science, and both regulated and competitive electricity and natural gas markets. Several of our senior-level staff members have more than 30 years of experience in the economics, regulation, and deregulation of the electricity and natural gas sectors. They have held positions as regulators, economists, and utility commission staff.

Services provided by Synapse include economic and technical analyses, regulatory support, research and report writing, policy analysis and development, representation in stakeholder committees, facilitation, trainings, development of analytical tools, and expert witness services. Synapse is committed to the idea that robust, transparent analyses can help to inform better policy and planning decisions. Many of our clients seek out our experience and expertise to help them participate effectively in planning, regulatory, and litigated cases, and other forums for public involvement and decision-making.

Synapse's clients include public utility commissions throughout the United States and Canada, offices of consumer advocates, attorneys general, environmental organizations, foundations, governmental associations, public interest groups, and federal clients such as the U.S. Environmental Protection Agency and the Department of Justice. Our work for international clients has included projects for the United Nations Framework Convention on Climate Change, the World Bank Group, the Global Environment Facility, and the International Joint Commission, among others.

Senior Associate Philip Eash-Gates is an energy engineer and environmental policy professional with a recent master's degree in Technology and Policy from MIT. For the last 11 years, he has worked in a professional capacity to implement sustainable energy and environmental initiatives for urban communities in the United States. He spent much of this time as the principal energy professional for the City of San Antonio, the nation's seventh largest municipality, where he served as technical and policy lead for clean energy projects and programs. His experience also includes directing the project division of a small energy services firm, as well as researching clean energy technology in one of MIT's leading energy labs. Over the span of 4,000 clean energy projects and 12 major policy initiatives, Mr. Eash-Gates has developed the expertise necessary to develop and deliver turnkey solutions to energy, economic, and environmental issues. His skillset includes techno-economic analysis, engineering and project design, policy and programmatic development, quality assurance and commissioning, and project finance. He has a Master of Science in Technology and Policy from the Massachusetts Institute of Technology and a Bachelor of Science in Engineering Science from Trinity University in San Antonio, TX.

Vice President Bob Fagan is a mechanical engineer and energy economics analyst who has analyzed energy industry issues for more than 30 years. He is an expert in the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the United States and Canada. His areas of focus include: wholesale energy and capacity provision under market-based and regulated structures; production cost modeling; transmission use pricing, encompassing congestion management, losses, LMP, and alternatives; renewable energy provision; and transmission asset pricing (e.g., embedded cost recovery tariffs).

His experience includes in-depth knowledge of physical transmission network characteristics; related generation dispatch/system operation functions; technical and economic attributes of generation resources; RTO and ISO tariff and market rules structures and operation; and FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution. Mr. Fagan is also expert in the assessment of technical and economic dimensions of wind and solar power integration into utility power systems, and in utility demand-side management and demand response impacts on the power system.

Mr. Fagan holds an MA from Boston University in energy and environmental studies and a BS from Clarkson University in mechanical engineering. He has completed additional course work in wind integration, solar engineering, regulatory and legal aspects of electric power systems, building controls, cogeneration, lighting design, and mechanical and aerospace engineering.

Senior Associate Devi Glick conducts economic analysis and writes testimony and publications that focus on a variety of issues related to energy and electric utilities. These issues include, non-exhaustively, power plant economics, utility resource planning practices, unit commitment and dispatch practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. Ms. Glick has submitted expert testimony on plant economics, utility resource needs, unit commitment practices, solar valuation, and tariff design in the states of Texas, New Mexico, Arizona, Indiana, Connecticut, Virginia, North Carolina, South Carolina, and Florida and in the province of Nova Scotia, and she has contributed to testimony and resource planning analysis in the states of Michigan, Alabama, and the province of Newfoundland.

Prior to joining Synapse, Ms. Glick worked at Rocky Mountain Institute as a Senior Associate on its Electricity and Energy Access programs. As a member of the Energy Access program, she developed Integrated Resource Planning modeling tools and carried out trainings for the utility and energy ministry in Rwanda on best practices for long-term resource planning in the electricity sector. Ms. Glick also worked to develop alternative utility business models for a major U.S. utility, led a project evaluating long-term utility resource planning trends in the United States, and led modeling work in collaboration with NextGen Climate America to evaluate the impact of a loophole in the Clean Power Plan.

Ms. Glick holds a Master of Public Policy and a Master of Science in Environmental Science from the University of Michigan, and a Bachelor of Arts in Environmental Studies from Middlebury College.

APPENDIX B: HISTORICAL AND FORECAST LOAD DATA FOR THE NHRLA

Table 8: Dominion Forecasted and Historical Summer Peak Demand (MW) for NHRLA

<table>
<tr><th>Year</th><th>Historical Load (MW)</th><th>2011 Load Forecast (MW)</th><th>2012 Load Forecast (MW)</th></tr>
<tr><td>2001</td><td>1,680</td><td colspan="2" rowspan="11"></td></tr>
<tr><td>2002</td><td>1,767</td></tr>
<tr><td>2003</td><td>1,735</td></tr>
<tr><td>2004</td><td>1,686</td></tr>
<tr><td>2005</td><td>1,942</td></tr>
<tr><td>2006</td><td>1,931</td></tr>
<tr><td>2007</td><td>1,988</td></tr>
<tr><td>2008</td><td>1,947</td></tr>
<tr><td>2009</td><td>1,844</td></tr>
<tr><td>2010</td><td>1,955</td></tr>
<tr><td>2011</td><td>1,969</td></tr>
<tr><td>2012</td><td>1,842</td><td>2,100</td><td>1,957</td></tr>
<tr><td>2013</td><td>1,799</td><td>2,187</td><td>2,021</td></tr>
<tr><td>2014</td><td>1,766</td><td>2,242</td><td>2,073</td></tr>
<tr><td>2015</td><td>1,893</td><td>2,288</td><td>2,139</td></tr>
<tr><td>2016</td><td rowspan="6">Not provided by Dominion</td><td>2,334</td><td>2,183</td></tr>
<tr><td>2017</td><td>2,365</td><td>2,208</td></tr>
<tr><td>2018</td><td>2,407</td><td>2,232</td></tr>
<tr><td>2019</td><td>2,448</td><td>2,260</td></tr>
<tr><td>2020</td><td>2,492</td><td>2,288</td></tr>
<tr><td>2021</td><td>2,532</td><td>2,308</td></tr>
</table>

Sources: Application of Virginia Electric and Power Company for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, Skiffes Creek 500 kV-230 kV-115 kV Switching Station (Dominion Application); SCC, Case No. PUE-2012-00029, June 2012. Appendix, Attachment I.B.1. and Attachment I.B.2. Dominion Energy. Surry – Skiffes Creek – Whealton Modeling and Alternatives Analysis Review. February 2, 2016.