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May 15, 2020

VIA ELECTRONIC DELIVERY

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603-5918

Re: Docket No. E-100 Sub 165
2020 Integrated Resource Plan of Virginia Electric and Power Company – Supplemental Information and Errata Pages

Dear Ms. Campbell:

Pursuant to §§ 62-2 and 62-110.1 of the North Carolina General Statutes and Rule R8-60(h)(1) of the Rules and Regulations of the North Carolina Utilities Commission (the "Commission"), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or the "Company"), encloses for electronic filing with the Commission corrected pages to the 2020 Integrated Resource Plan (the "2020 Plan") filed in the above-captioned proceeding on May 1, 2020, which are intended to correct two identified errors. First, the natural gas-fired generation preserved under Alternative Plan B should be approximately 9,500 MW rather than 9,700 MW. This correction affects pages 3, 6, 27, 101, and 119 of the 2020 Plan. Second, the title of Figure 2.2.5 on page 30 of the 2020 Plan should be "CO2 Output from Company Fleet for Alternative Plans." The corrected pages enclosed at Attachment A hereto are intended to replace the versions filed on May 1, 2020, and were also filed with the State Corporation Commission of Virginia ("VSCC") on May 14, 2020 in Case No. PUR-2020-00035. In addition, enclosed as Attachment B hereto is supplemental information related to the 2020 Plan, which the Company also filed with the VSCC on May 14, 2020.

Please do not hesitate to contact me if you have any questions. Thank you for your assistance in this matter.

Very truly yours,

/s/*Andrea R. Kells*

ARK:sjg

Enclosures

cc: Lucy Edmondson, Public Staff—North Carolina Utilities Commission
Layla Cummings, Public Staff—North Carolina Utilities Commission
Nadia L. Luhr, Public Staff—North Carolina Utilities Commission

- The retirement of over 2,200 MW of coal-fired and inflexible, higher cost oil- and natural gas-fired generation over the past ten years;
- The construction of approximately 198 MW of solar generation over the past ten years, with an additional 198 MW of solar generation currently under construction;
- The procurement of approximately 874 MW of solar NUGs over the past ten years;
- The continued work to extend the licenses of the Company's nuclear units at Surry and North Anna;
- The construction of the Coastal Virginia Offshore Wind ("CVOW") demonstration project, along with the development of a larger build-out of offshore wind generation off the coast of Virginia;
- The continued transformation of the Company's distribution grid to provide an enhanced platform for distributed energy resources ("DERs") and targeted DSM programs; more secure and reliable service, leading to the increased availability of DERs; and more ways for customers to save energy and money through DSM programs and other rate offerings; and
- The continued work associated with energy storage technology, including the development of a new pumped storage hydroelectric facility in Virginia and the deployment of three battery energy storage system ("BESS") pilot projects.

Over the long term, however, achieving the clean energy goals of Virginia, North Carolina, and the Company will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy. This includes support for the testing and deployment of technologies such as large-scale energy storage, hydrogen, advanced nuclear, and carbon capture and sequestration, all of which have the potential to significantly reduce greenhouse gas emissions.

In this 2020 Plan, the Company presents four alternative plans (the "Alternative Plans"). Except for Alternative Plan A, all Alternative Plans assume that Virginia is a full RGGI participant.

- Plan A – This Alternative Plan presents a least-cost plan that estimates future generation expansion where there are no new constraints, including no new regulations or restrictions on CO_2 emissions. Plan A is presented for cost comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, this Alternative Plan does not represent a realistic state of relevant law and regulation.

- Plan B – This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves approximately ~~9,700~~9,500 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues. While Plan B—and indeed all Alternative Plans—incorporate only known, proven technologies, the Company fully expects that new technologies could take the place of today's technologies over the Study Period. Overall, Plan B is the lowest cost of Alternative Plans B, C, and D, decreases the reliance on outside markets to meet customer demand and produces similar regional CO_2 emissions as Plans C and D. Over the same manner as modeled due to many outside factors. These factors include the ability of future vendors to deliver program savings at the assumed fixed price, the desire of customers to participate in the program at that price, and the effectiveness of the program to be administered at that price. The modeled costs and level of savings attributable to generic energy efficiency are thus placeholders as future phases of actual energy efficiency programs are developed and implemented.

From a permitting perspective, all Alternative Plans include large quantities of solar capacity located in Virginia. In fact, to meet customers' demand, Alternative Plans B through D require between 31,400 MW and 40,640 MW of new solar capacity by 2045. Given current technology, 31,400 MW of solar generating capacity in the Commonwealth would require the land use of 490 square miles. This land mass is nearly 25% larger than Fairfax County, Virginia, or the equivalent of nearly 237,000 football fields. Utilization of such a large land mass area for energy generation will likely encounter local and environmental permitting issues.

The large quantities of solar capacity in Alternative Plans B through D also pose challenges from a technical perspective. A key component included in the traditional design of the North American electric power grid is the inertia from many existing traditional turbines to create a reservoir of kinetic energy. This kinetic energy automatically provides grid support by balancing the myriad of instantaneous discrepancies between generation and load at any moment in time. Inverter-based generation such as intermittent solar and wind resources do not provide such a reservoir of kinetic energy. Therefore, the retirement of traditional generation units coupled with the addition of large quantities of intermittent renewable generation will adversely affect both electric system reliability and the Company's ability to restore the system in the event of a large-scale blackout. Transmission planning work has begun, but more planning analysis is necessary to model the grid under different conditions to assure system reliability, stability, and security with the retirement of traditional generation. Although Plans B through D show significantly reduced carbon emissions by 2045 associated with these projected retirements, additional transmission and distribution projects potentially needed to address system reliability and security have not been fully assessed and evaluated in this 2020 Plan. The Company will provide the results of these additional analyses in future Plans and update filings.

In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

In Alternative Plan B, the Company preserved approximately ~~9,700~~9,500 MW of efficient natural gas-fired generation units to address these future system reliability, stability, and energy independence issues. In future Plans, these units could be replaced by new types of generation such as small modular reactors. These units could also be transformed into low-carbon or carbon-free generation by installing new technologies such as carbon capture sequestration or

- Plan A – This Alternative Plan presents a least-cost plan that estimates future generation expansion where there are no new constraints, including no new regulations or restrictions on CO_2 emissions. Plan A is presented for cost comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, this Alternative Plan does not represent a realistic state of relevant law and regulation.

- Plan B – This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves approximately ~~9,700~~ 9,500 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues.

- Plan C – This Alternative Plan uses similar assumptions as Plan B, but retires all Company-owned carbon-emitting generation in 2045, resulting in close to zero CO_2 emissions from the Company's fleet in 2045. To reach zero CO_2 emissions in 2045, Plan C significantly increases the amount of energy storage resources and the level of imported power.

- Plan D – This Alternative Plan uses similar assumptions as Plan C, but changes the capacity factor assumption for future solar resources from 25% to 19%. As a result, Plan D significantly increases the amount of solar resources needed to reach zero CO_2 emissions in 2045.

Figures 2.2.1 through 2.2.4 show the build plans for each Alternative Plan. See Appendix 2A for the capacity and energy associated with all Alternative Plans.

have to ramp over 30,000 MW of supply—an extremely large magnitude, especially over that short of a duration. Essentially, the Company would be ramping up and down its entire fleet of dispatchable resources twice a day. Backup generation resources along with energy storage resources may be required to manage these large transitions.

5.6.4 Challenges Related to Black Start and System Restoration

"Black start" refers to the critical process of restoring the system without relying on the external transmission network to recover from a total or partial shutdown. Development of significant volumes of solar generation also present challenges in a black start event. The system has traditionally been set up to rely on dispatchable, quick-start units for black start, such as combustion turbines. Initial power from these units are used to start larger dispatchable generators, allowing even larger units (*e.g.*, nuclear) and customers to reconnect to the grid in a very logical and coordinated process. This process is largely a manual process for grid operators as they must maintain a fine balance between energy supply and demand; black start units thus have strict operational requirements to be available around-the-clock and be able to produce steady and predictable output. Such requirements impose difficulties for non-dispatchable, intermittent solar resources to be included in the system restoration plan.

In this 2020 Plan, Alternative Plan B preserves approximately ~~9,700~~ 9,500 MW of natural gas-fired generation to address future system reliability, stability and energy independence, including challenges related to black start. The Company will continue to study how to address these black start-related challenges as the Company transition to a cleaner future, as discussed further in Section 7.5.5.

5.6.5 Challenges Related to Constructability

Beyond the system challenges that arise from adding increasing amounts of intermittent generation to the system, solar developers—including the Company—will face increasing challenges in permitting and constructing the amount of solar generation envisioned by the VCEA, as modeled in Alternative Plans B through D.

Utility-scale solar generating facilities require a significant amount of land. Based on current technology, every one megawatt of solar capacity requires approximately 10 acres of land. The VCEA requires this new solar capacity to be located in Virginia. Acquiring this amount of land—and receiving the required permits for that land—could prove increasingly difficult as development continues.

This difficulty in acquiring land and permitting projects will be exacerbated if localities and members of the public continue to raise objections to siting solar facilities in their communities. For example, in October 2019, the Culpepper County Board of Supervisors adopted new provisions to its Utility Scale Solar Development Policy intended "to limit 'utility scale solar sprawl.'" These new provisions would limit total solar development in the county to 2,400 acres—1% of the total land mass in Culpeper—and would limit the size of individual projects to 300 acres (the equivalent of approximately 30 MW). As another example, in Spotsylvania County, Virginia, neighboring property owners and community members have filed complaints lines ("Interregional Transmission Lines"). These multistate lines would have to interconnect with generation resources located in the PJM system and terminating in major load centers in Virginia, like Northern Virginia, the Richmond metropolitan area, and the Hampton Roads metropolitan area. These Interregional Transmission Lines could be either alternating current ("AC") or direct current ("DC") transmission lines. The Trail Project, built in 2006 at a cost of approximately $1.2 billion and going from Pennsylvania to West Virginia to Virginia, was the most recent type of interregional transmission facility built on the PJM system. Further, additional generation resources located in the DOM Zone would be needed in order to address the amount of intermittent renewable resources being added to the system in the Planning Period. These generation resources would need to be quick start and capable of continued operation that is not impacted by weather conditions.

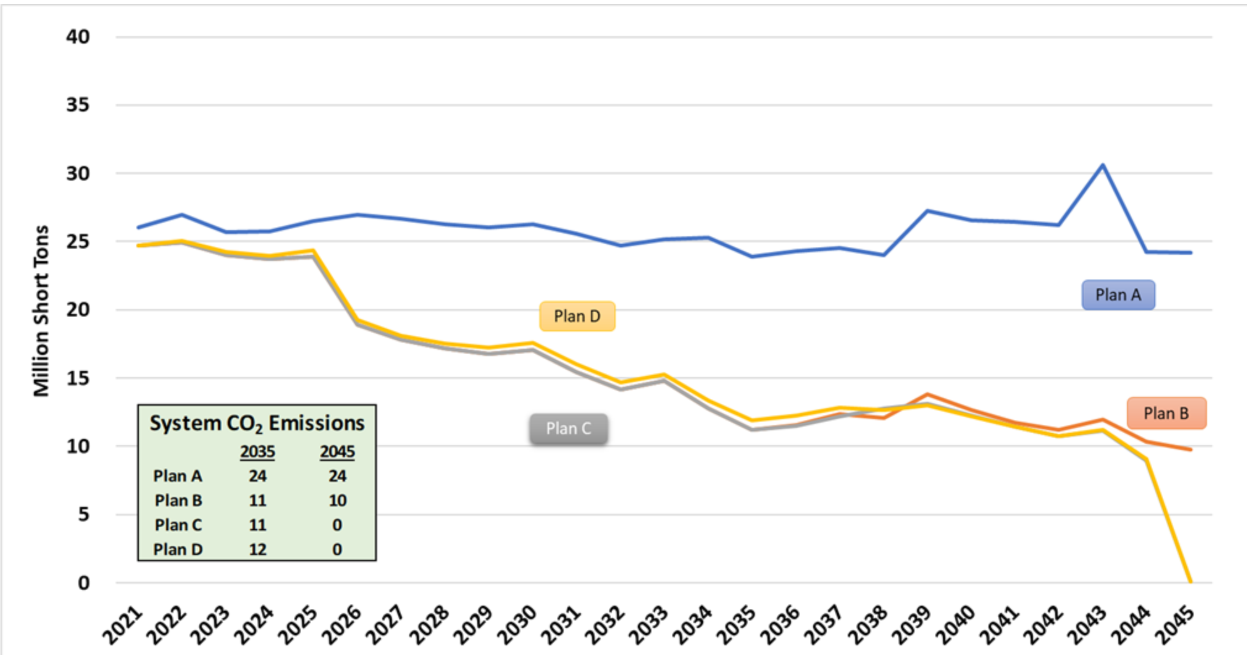
As shown in the Figure 5.6.2.2, Alternative Plans A, B, C, and D require the Company's transmission system to be able to import 5,200 MW to serve the DOM Zone load in the Planning Period, and between 5,200 MW (Alternative Plans A and B) and 10,400 MW (Alternative Plans C and D) to be able to serve DOM Zone load in the Study Period. The transmission impacts related to each of the Alternative Plans is summarized below.

- Plan A – Normal transmission planning expected with no additional transmission level import increase required to maintain 5,200 MW of import capability. Since Alternative Plan A has a smaller portion of its generation resources that are impacted by weather conditions (*i.e.*, renewable generation) and fewer generation retirements, this alternative still reflects the DOM Zone operating in a firm operational state not dependent upon weather conditions.
- Plan B – Normal transmission planning expected with no additional transmission level import increase costs required to maintain 5,200 MW of import capability. While Alternative Plan B has a larger amount of solar, energy storage, and offshore wind resources added as compared to Alternative Plan A, Plan B preserves approximately ~~9,700~~9,500 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues as compared to Alternative Plan A and, therefore, construction of Interregional Transmission Lines are not anticipated.
- Plan C – This alternative will require additional transmission level import increase costs in order to construct Interregional Transmission Lines to obtain 10,400 MW of import capability. Alternative Plan C has a larger amount of solar, energy storage, and offshore wind resources added as compared to Alternative Plan A, as well as significantly more generation retirements of the existing DOM Zone generation fleet as compared to Alternative Plan A. As a result, four Interregional Transmission Lines would need to be constructed at a placeholder estimated cost of approximately $8.4 billion.
- Plan D – This alternative will require additional transmission level import increase costs in order to construct Interregional Transmission Lines to obtain 10,400 MW of import capability. While Alternative Plan D has a larger amount of solar resources added than Alternative Plan C and a larger amount of energy storage and offshore wind resources added as compared to Alternative Plan A, based on capacity factors, there is no change in the amount of generation retirements of the existing DOM Zone generation fleet as

Alternative Plans B, C, and D include 970 MW of natural gas-fired CTs as a placeholder to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

Figure 2.2.5 shows the CO_2 emissions from the Company's fleet for each Alternative Plan, while Figure 2.2.6 shows the regional CO_2 emissions for each Alternative Plan. Because the regional CO_2 emissions capture the effects of both energy imports and exports required to meet customer needs, the regional emissions are a better indicator of customers' impact on the environment.

Figure 2.2.5 – ~~Virginia~~ CO_2 Output from Company Fleet for Alternative Plans



2020 Integrated Resource Plan
Supplemental Information
Case No. PUR-2020-00035

On May 1, 2020, Virginia Electric and Power Company (the "Company") filed its 2020 Integrated Resource Plan ("2020 Plan") with the Virginia State Corporation Commission. Along with the 2020 Plan, the Company filed two addenda: (i) Virginia Addendum 1, the details of a Virginia residential bill analysis, and (ii) Virginia Addendum 2, the Grid Transformation Plan Document. The Company now provides the following supplemental information.

Supplement to Executive Summary

In addition to the four Alternative Plans presented in the 2020 Plan, the Company presents a fifth Alternative Plan:

- Plan B_{19} – This Alternative Plan uses the same assumptions as Plan B but changes the capacity factor assumption for future solar resources from 25% to 19%. As a result, Plan B_{19} increases the amount of solar resources needed to meet customer demand. Specifically, over the 25-year Study Period, this Plan includes approximately 9.2 gigawatts of incremental solar capacity as compared to Plan B. Like Plan B, Plan B_{19} preserves approximately 9,500 megawatts ("MW") of natural gas-fired generation to address future system reliability, stability, and energy independence issues.

The following supplemental table presents a high-level summary of the Alternative Plans:

Supp. Executive Summary Table: 2020 Plan Results

	Plan A	Plan B	Plan B_{19}	Plan C	Plan D
NPV Total ($B)	$44.3	$66.2	$68.6	$78.6	$80.8
Approximate CO_2 Emissions from Company in 2045 (Tons)	24 M	10 M	10 M	0	0
Approximate CO_2 Emissions Regionally in 2045 (Tons)	34 M	4 M	4 M	4 M	5 M
Solar (MW)	6,720 15-year 11,520 25-year	15,920 15-year 31,400 25-year	18,800 15-year 40,640 25-year	15,920 15-year 32,480 25-year	18,800 15-year 40,640 25-year
Offshore Wind (MW)	--- 15-year --- 25-year	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year
Storage (MW)	--- 15-year --- 25-year	2,714 15-year 5,114 25-year	2,714 15-year 5,114 25-year	2,714 15-year 9,914 25-year	2,714 15-year 9,914 25-year
Natural Gas-Fired (MW)	1,940 15-year 3,531 25-year	970 15-year 970 25-year	970 15-year 970 25-year	970 15-year 970 25-year	970 15-year 970 25-year
Import / Export Capability (MW)	5,200 15-year 5,200 25-year	5,200 15-year 5,200 25-year	5,200 15-year 5,200 25-year	5,200 15-year 10,400 25-year	5,200 15-year 10,400 25-year
Retirements (MW)	3,030 15-year 4,651 25-year	3,183 15-year 5,414 25-year	3,183 15-year 5,414 25-year	3,183 15-year 13,978 25-year	3,183 15-year 13,978 25-year

Plans B_{19} and D are Alternative Plans that use the "baseline assumption" of a 19% capacity factor for future solar resources. Plans B and C can be considered to be "sensitivities" of Plans B_{19} and D, respectively, using a 25% capacity factor for future solar resources.

Supplement to Section 2.2: Alternative Plans

In addition to the four Alternative Plans presented in the 2020 Plan, the Company presents a fifth Alternative Plan:

- Plan B_{19} – This Alternative Plan uses the same assumptions as Plan B but changes the capacity factor assumption for future solar resources from 25% to 19%. As a result, Plan B_{19} increases the amount of solar resources needed to meet customer demand. Plan B can be considered to be a "sensitivity" of Plan B_{19}.

Figure 2.2.7 shows the build plans for Alternative Plan B_{19}.

Figure 2.2.7 - Alternative Plan B_{19} (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	960	360	220	852	400				
2027	960	480		1,704	500				Rosemary
2028	960	480	220						AV, HW, SH
2029	960	480			500				
2030	960	600	220			300			
2031	960	600							
2032	960	600			500			Surry 1	
2033	960	600						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	11,460	6,240	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

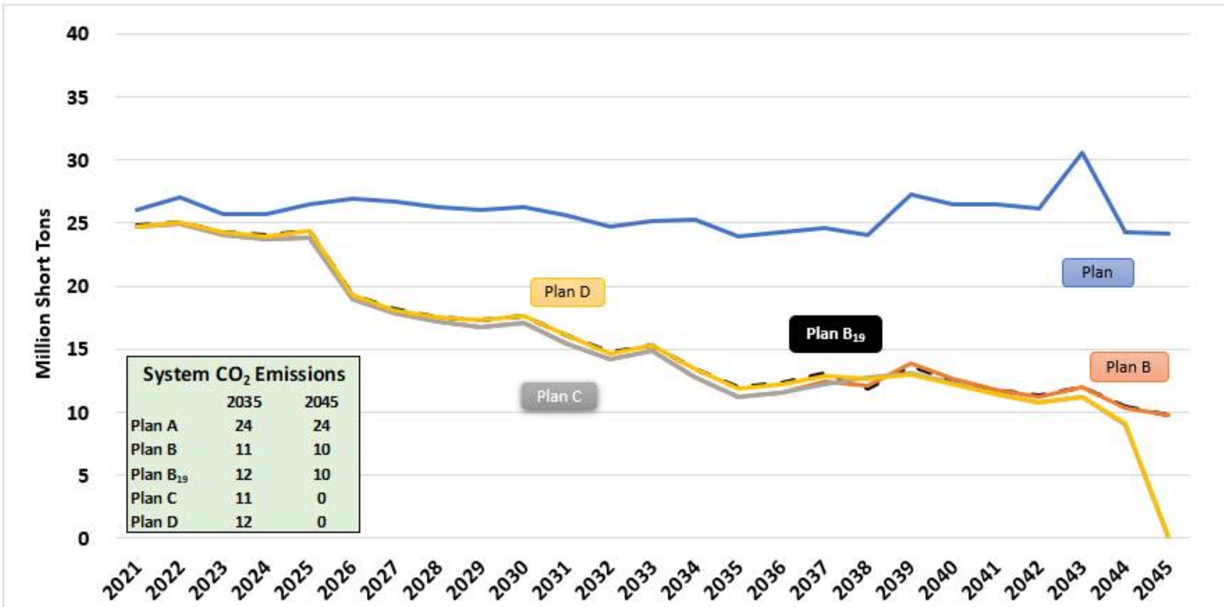
"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Like Alternative Plans B, C, and D, Alternative Plan B_{19} includes 970 MW of natural gas-fired combustion turbines as a placeholder to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

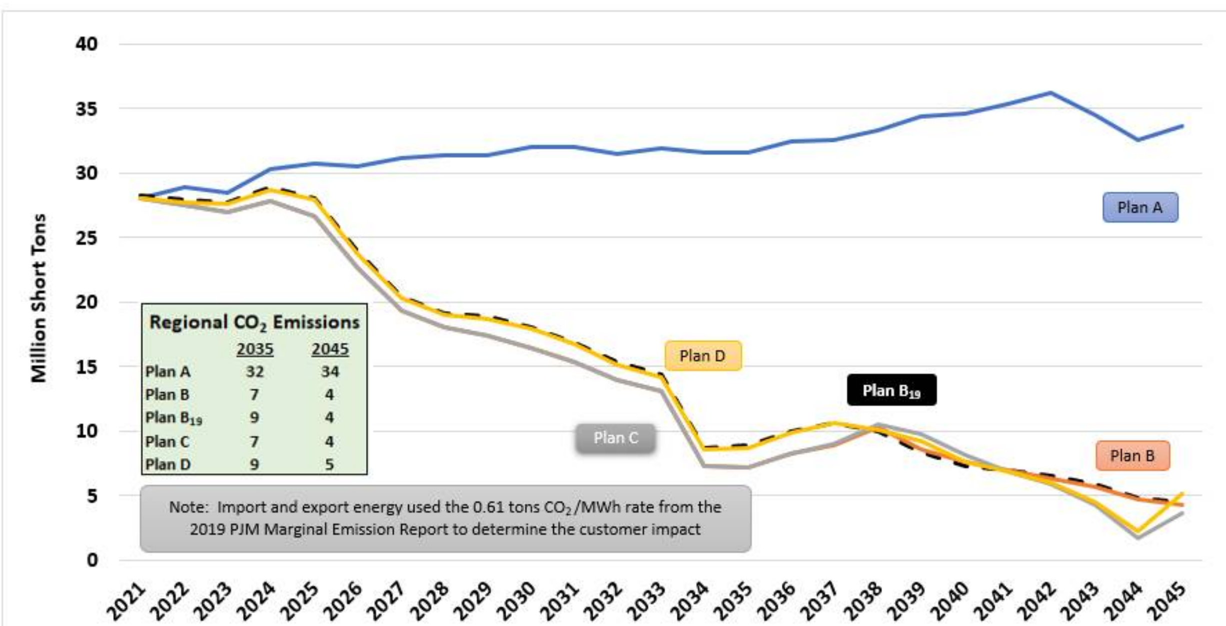
Supp. Figure 2.2.5 shows the carbon dioxide ("CO_2") emissions from the Company's fleet for each Alternative Plan, while Supp. Figure 2.2.6 shows the regional CO_2 emissions for each

Alternative Plan. Because the regional CO_2 emissions capture the effects of both energy imports and exports required to meet customer needs, the regional emissions are a better indicator of customers' impact on the environment.

Supp. Figure 2.2.5 – CO_2 Output from Company Fleet for Alternative Plans



Supp. Figure 2.2.6 – Regional CO_2 Output for Alternative Plans



Supplement to Section 2.4: NPV Results

Supp. Figure 2.4.1 presents the net present value ("NPV") results for each build plan over the Study Period on the "Total System Costs" line, as well as the estimated NPV of proposed investments in the Company's transmission and distribution systems, broken down by specific line item.

Supp. Figure 2.4.1 – NPV Results

2020 $B	Plan A	Plan B	Plan B_{19}	Plan C	Plan D
Total System Costs[1]	$ 34.7	$ 56.8	$ 59.2	$ 60.7	$ 63.0
GT Plan	$ 0.2	$ 3.2	$ 3.2	$ 3.2	$ 3.2
SUP	$ 2.2	$ 2.2	$ 2.2	$ 2.2	$ 2.2
Broadband	$ -	$ 0.2	$ 0.2	$ 0.2	$ 0.2
Transmission Underground Pilot	$ -	$ 0.2	$ 0.2	$ 0.2	$ 0.2
Transmission	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1
Transmission Level Import Increase	$ -	$ -	$ -	$ 8.4	$ 8.4
Customer Growth	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0
Subtotal Plan NPV[2]	**$ 44.3**	**$ 69.7**	**$ 72.1**	**$ 82.1**	**$ 84.3**
Less Benefits of GT Plan	$ -	$ (3.5)	$ (3.5)	$ (3.5)	$ (3.5)
Total Plan NPV	**$ 44.3**	**$ 66.2**	**$ 68.6**	**$ 78.6**	**$ 80.8**
Plan Delta vs. Plan A	**$ -**	**$ 21.9**	**$ 24.3**	**$ 34.3**	**$ 36.6**

Notes: (1) Total system costs include the results from Figures 2.2.1 through 2.2.4 plus approved, proposed, and generic DSM; solar interconnection costs; and solar integration costs. (2) Numbers may not add due to rounding.

Supplement to Section 2.5: Virginia Residential Bill Analysis

The Company calculated the projected bill of a typical residential customer in Virginia using 1,000 kWh for Alternative Plan B_{19} over each of the next ten years. Figure 2.5.3 presents the summary results of these projections in 2030—in addition to the summary results for Alternative Plan B—compared to the bill of a typical residential customer as of May 1, 2020. Figure 2.5.3 shows a projected total bill increase of $52.40 for Plan B compared to a projected total bill increase of $45.92 for Plan B shown in Figure 2.5.1. This difference of $6.48 is attributable to decrease in rates between December 31, 2019, and May 1, 2020, largely attributable to a significant decrease in the fuel factor. Notably, the decrease in the fuel factor was effective on an interim basis May 1, 2020—after the 2020 Regular Session of the Virginia General Assembly. Changes to the Company's fuel factor typically become effective as of July 1 each year, but the Company requested an accelerated implementation of the reduction to benefit customers. The $2.62 increase between Plan B and Plan B_{19} is attributable to additional solar generation in Alternative Plan B_{19}. Importantly, these bill projections are not final—all Company rates are subject to regulatory approval.

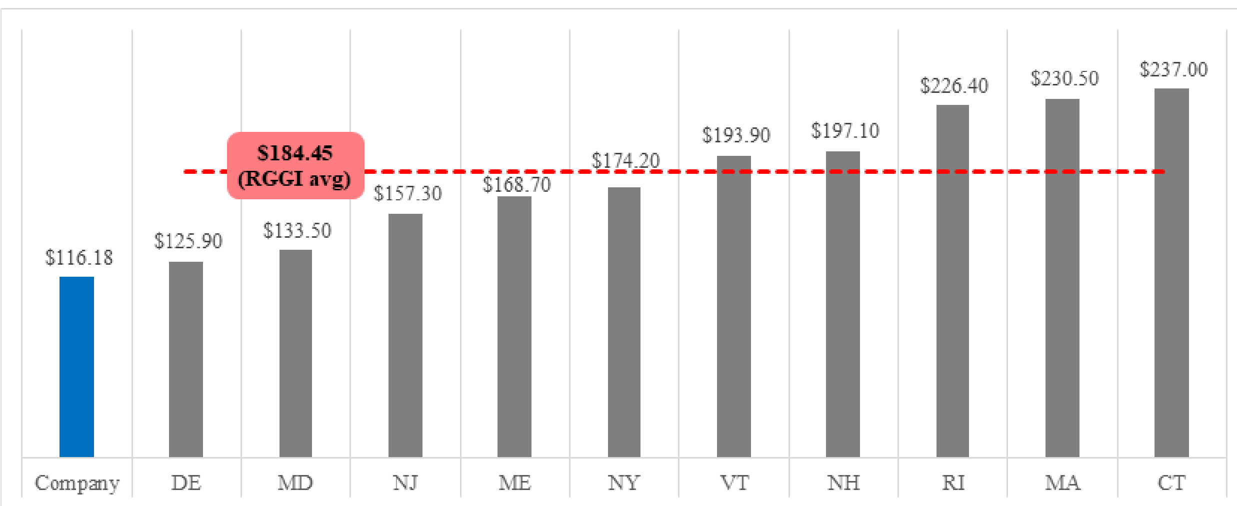
Figure 2.5.3 – Residential Bill Projection for Plan B and Plan B_{19} (1,000 kWh per Month)

	Plan B_{19}		Plan B	
	Projected Bill	CAGR	Projected Bill	CAGR
May 1, 2020	$116.18		$116.18	
Plan A[1]	$18.18	1.4%	$18.18	1.4%
Pre-2020 Legislation[2]	$15.01	1.0%	$15.28	1.0%
2020 Legislation[3]	$21.83	1.3%	$18.94	1.2%
Total 2030 Year End	**$171.20**	**3.7%**	**$168.58**	**3.6%**
Total Bill Increase	$55.02		$52.40	

Notes: (1) Represents bill projections associated with future generation in Alternative Plan A; approved and proposed investments in demand-side management programs; approved investments in the Grid Transformation Plan (*i.e.* Phase IA and IB); investments in the Strategic Underground Program; and compliance with environmental laws and regulations, including coal combustion residuals investments. (2) Represents bill projections associated with future generation in Alternative Plan B or B_{19}, as applicable, and other investments incentivized or mandated by legislation prior to 2020, including legislation related to pumped storage (2017), the GTSA (2018), and rural broadband (2019). (3) Represents bill projections associated with future generation in Alternative Plan B or B_{19}, as applicable, and other investments incentivized or mandated by the VCEA and other 2020 legislation.

Figure 2.5.4 shows the average residential rate for RGGI states normalized for 1,000 kWh monthly usage—approximately $184.45—compared to the Company's typical residential bill as of May 1, 2020 (*i.e.*, $116.18).

Figure 2.5.4 – Residential Bill Comparison for RGGI States, with May 1, 2020 Company Bill[1]

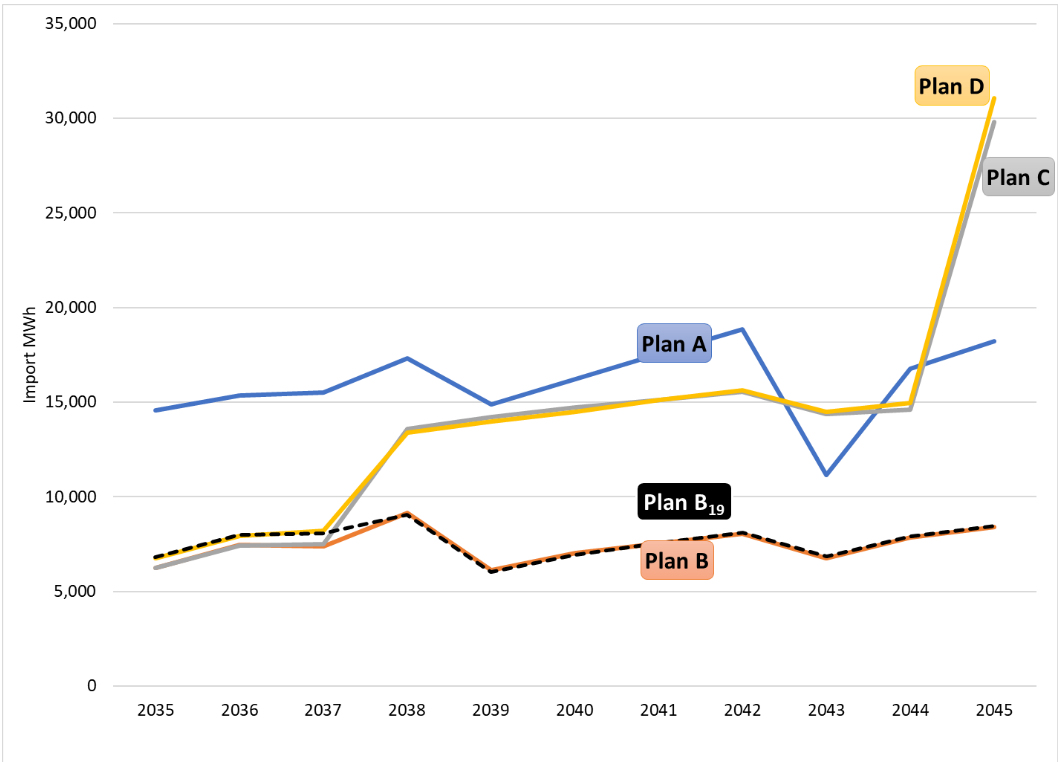


Note: (1) Based on residential rate data for RGGI states from U.S. Energy Information Administration as of February 2020, normalized for 1,000 kilowatt-hour monthly usage. Typical 1,000 kilowatt-hour residential bill for Company as of May 1, 2020.

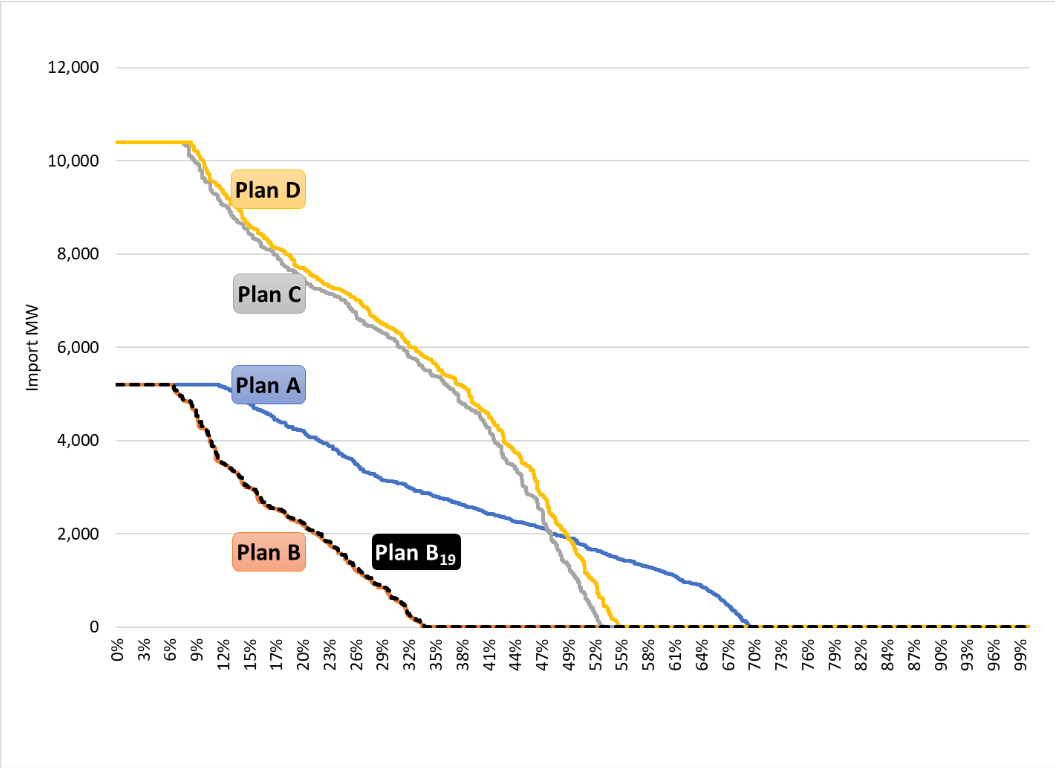
Supplement to Section 5.6.2: Challenges Related to Energy

Supp. Figure 5.6.2.1 shows the level of imports for each Alternative Plan. Supp. Figure 5.6.2.2 shows what percentage of time in the year 2045 the Company must use imports to meet load.

Supp. Figure 5.6.2.1 – Annual Imports for Each Alternative Plan



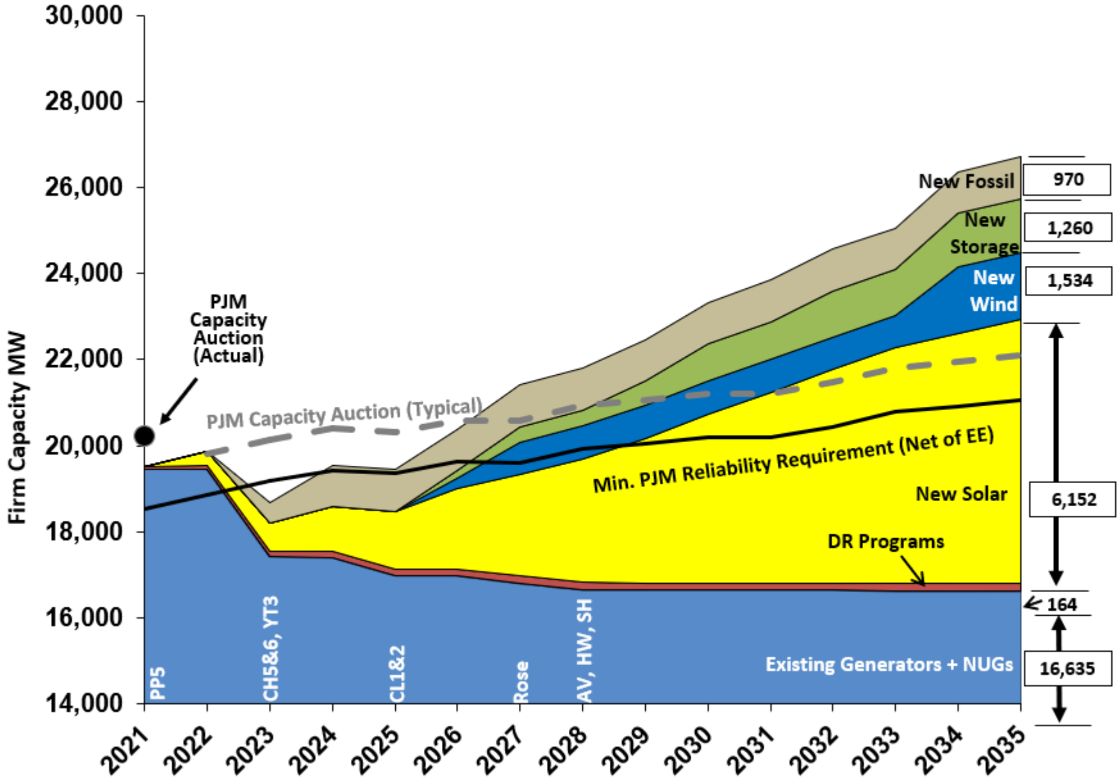
Supp. Figure 5.6.2.2 – Year 2045 Import Duration Curve

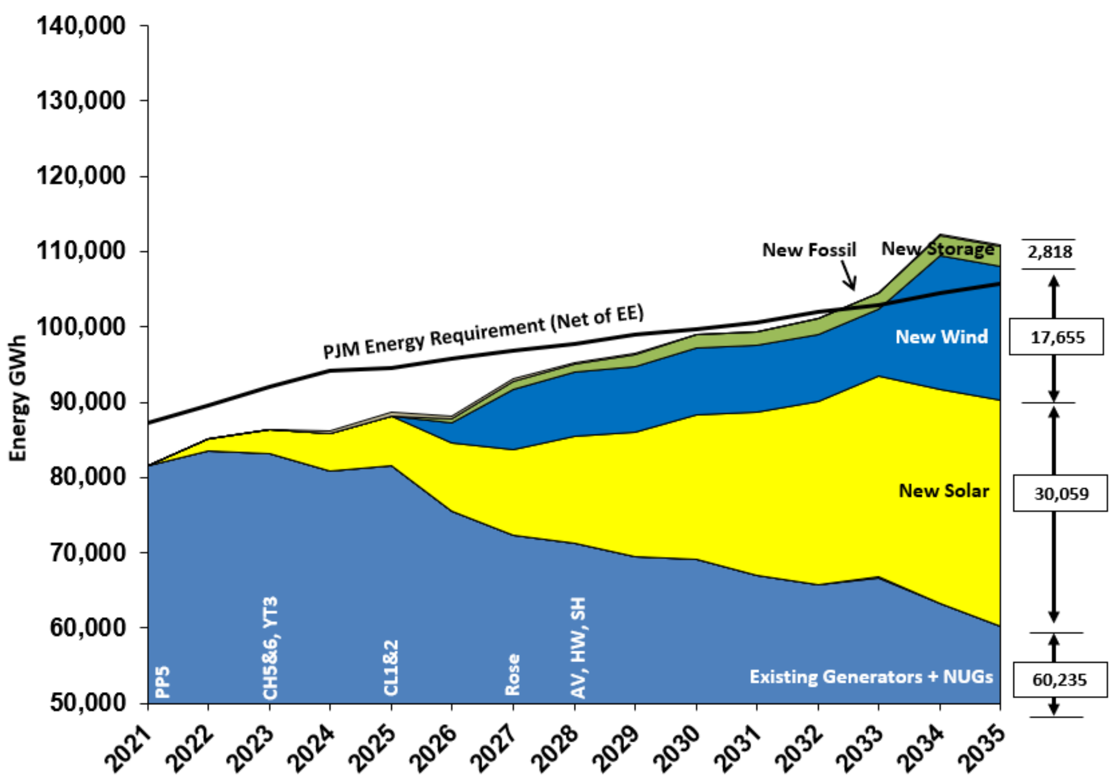


Supplement to Appendices

Supp. Appendix 2A shows the capacity and energy associated with Alternative Plan B_{19}. Appendices 4S and 5T through 5AC provide additional results for Plan B_{19}.

Supp. Appendix 2A – Plan B19 – Capacity and Energy





Appendix 4S – Required Reserve Margin for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 6**

POWER SUPPLY DATA (continued)

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. Reserve Margin(1)																			
1. Summer Reserve Margin																			
a. MW(1)	3,799	2,946	3,399	3,480	3,387	2,746	2,125	2,042	1,846	2,624	3,593	3,933	4,305	5,056	5,417	5,961	6,221	7,380	7,601
b. Percent of Load	23.2%	17.8%	20.5%	21.2%	20.4%	16.3%	12.5%	11.9%	10.7%	15.1%	20.5%	22.2%	24.1%	28.1%	29.9%	32.6%	33.6%	39.5%	40.4%
c. Actual Reserve Margin(2)	N/A	N/A	N/A	20.0%	18.6%	14.8%	10.4%	9.4%	7.7%	11.8%	16.7%	18.7%	20.7%	24.6%	26.3%	28.8%	30.4%	36.4%	37.4%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	4,343	4,170	3,095	2,025	1,525	829	1,155	1,671	1,315	1,203	1,522	1,235	1,323	1,066	1,892	1,743
b. Percent of Load	N/A	N/A	N/A	26.3%	25.0%	18.1%	11.6%	8.6%	4.6%	6.4%	9.2%	7.1%	6.5%	8.2%	6.5%	7.0%	5.5%	9.8%	8.9%
c. Actual Reserve Margin(2)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
II. Annual Loss-of-Load Hours(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) To be calculated based on Total Net Capability for summer and winter.
(2) Does not include spot purchases of capacity or Energy Efficiency programs.
(3) The Company follows PJM reserve requirements which are based on LOLE.

Appendix 5T – Equivalent Availability Factor for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA
Equivalent Availability Factor (%)

Unit Name	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	(ACTUAL)			(PROJECTED)															
Altavista	63	75	79	92	90	90	100	100	85	85	85	85	100	-	-	-	-	-	-
Bath County 1-6	90	82	87	91	91	89	89	92	91	91	91	91	91	91	91	91	91	91	91
Battery_Gen1				-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100
Battery_Gen2				-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100
Battery_Gen3				-	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100
Battery_Gen4				-	-	-	-	-	-	-	-	-	-	-	-	100	100	100	100
Battery_Gen5				-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Bear Garden	80	85	73	79	77	80	80	82	79	79	79	79	79	79	79	79	79	79	79
Brunswick	82	84	74	81	81	76	85	84	80	80	80	80	80	80	80	80	80	80	80
Chesapeake CT 1, 4, 6	99	94	85	90	90	89	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	65	57	47	77	87	84	100	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	59	47	51	73	79	84	100	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	84	69	78	71	92	80	92	85	87	87	87	87	87	87	87	87	87	87	87
Chesterfield 8	86	75	77	59	92	81	85	92	84	84	84	84	84	84	84	84	84	84	84
Clover 1	88	86	61	83	86	88	86	86	100	-	-	-	-	-	-	-	-	-	-
Clover 2	65	71	75	86	86	88	88	86	100	-	-	-	-	-	-	-	-	-	-
CVOW - Phase 1 (880MW)				-	-	-	-	-	-	35	37	40	39	39	39	40	39	39	39
CVOW - Phase 2 (880MW)				-	-	-	-	-	-	-	35	37	39	39	39	40	39	39	39
CVOW - Phase 3 (880MW)				-	-	-	-	-	-	-	35	37	39	39	39	40	39	39	39
CVOW (Pilot)				-	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Darbytown 1	92	97	89	67	93	85	93	93	90	90	90	90	90	90	90	90	90	90	90
Darbytown 2	93	87	97	94	94	87	71	94	90	90	90	90	90	90	90	90	90	90	90
Darbytown 3	89	97	89	94	94	87	94	94	90	90	90	90	90	90	90	90	90	90	90
Darbytown 4	92	73	93	94	94	87	94	94	90	90	90	90	90	90	90	90	90	90	90
Elizabeth River 1	93	90	90	58	87	94	94	94	90	90	90	90	90	90	90	90	90	90	90
Elizabeth River 2	92	76	75	93	87	94	94	69	90	90	90	90	90	90	90	90	90	90	90
Elizabeth River 3	92	80	94	92	87	94	94	94	90	90	90	90	90	90	90	90	90	90	90
Gaston Hydro	91	91	77	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Generic Brownfield CT				-	-	-	92	92	92	92	92	92	92	92	92	92	92	92	92
Generic Solar PV- (60MW)				-	-	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Generic Solar PV PPA Post 2022				-	-	-	19	19	19	19	19	19	19	19	19	19	19	19	19
Generic Solar PV PPA Pre 2022				-	-	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Generic Storage - Battery (Pilot) -14MW				-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Generic Storage - Battery (Pilot) -16MW	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Gordonsville 1	77	74	84	77	83	89	79	84	84	84	84	84	84	84	84	84	84	84	84
Gordonsville 2	52	82	83	70	75	84	89	86	85	85	85	85	85	85	85	85	85	85	85
Gravel Neck 1-2	100	95	93	89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	90	100	95	87	91	94	94	94	90	90	90	90	90	90	90	90	90	90	90
Gravel Neck 4	87	90	95	87	94	91	94	94	90	90	90	90	90	90	90	90	90	90	90
Gravel Neck 5	91	96	95	87	94	94	94	94	90	90	90	90	90	90	90	90	90	90	90
Gravel Neck 6	91	98	97	87	94	91	94	94	90	90	90	90	90	90	90	90	90	90	90

Note: EAF for intermittent resources shown as a capacity factor.

Appendix 5T cont. – Equivalent Availability Factor for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA
Equivalent Availability Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Greensville	-	96	73	80	81	79	80	78	79	79	79	79	79	79	79	79	79	79	79
Hopewell	78	83	83	43	88	88	100	100	82	82	82	82	100	-	-	-	-	-	-
Ladysmith 1	85	93	86	90	90	90	79	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 2	85	94	86	90	90	90	79	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 3	84	74	87	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 4	77	79	87	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 5	83	95	87	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Lowmoor CT 1-4	98	98	99	91	91	91	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	74	76	64	80	82	76	76	87	81	81	81	81	81	81	81	81	81	81	81
Mount Storm 2	81	66	60	70	76	86	86	81	81	81	81	81	81	81	81	81	81	81	81
Mount Storm 3	71	72	54	76	86	76	86	88	82	82	82	82	82	82	82	82	82	82	82
Mount Storm CT	96	79	98	90	90	89	-	-	-	-	-	-	-	-	-	-	-	-	-
New Pump Storage				-	-	-	-	-	-	-	-	-	-	70	70	70	70	70	70
North Anna 1	100	90	93	98	89	91	98	79	91	98	91	84	98	84	91	98	91	91	98
North Anna 2	90	99	88	89	98	91	77	98	91	91	98	91	84	98	84	91	91	98	91
North Anna Hydro	100	100	100	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
Northern Neck CT 1-4	94	99	97	90	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	62	57	69	77	84	100	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	75	83	69	60	72	82	84	77	75	75	75	75	75	75	75	75	75	75	75
Possum Point CT 1-6	97	95	100	90	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	91	94	79	89	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Remington 2	91	87	79	89	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Remington 3	70	89	76	89	90	87	90	90	90	90	90	90	90	90	90	90	90	90	90
Remington 4	83	88	79	89	90	87	90	90	90	90	90	90	90	90	90	90	90	90	90
Roanoke Rapids Hydro	92	90	72	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Rosemary	78	78	85	92	83	96	83	96	90	90	100	100	100	100	100	100	100	100	100
Scott Solar				19	19	19	19	19	19	19	18	18	18	18	18	18	18	18	18
Solar Partnership Program				14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Solar_DG				-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Southampton	68	84	83	92	92	90	100	100	84	84	84	84	100	-	-	-	-	-	-
Surry 1	99	87	89	98	91	91	98	84	84	98	84	91	98	74	91	100	100	100	100
Surry 2	92	89	100	87	91	98	91	84	98	82	84	98	74	91	98	98	100	100	100
US-3 Solar 1				19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
US-3 Solar 2				-	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
US-4 Solar				-	19	19	19	18	19	19	19	18	19	19	19	18	19	19	19
Virginia City Hybrid Energy Center	74	64	55	75	78	78	78	78	77	77	77	77	77	77	77	77	77	77	77
Warren	88	78	80	81	72	81	81	81	79	79	79	79	79	79	79	79	79	79	79
Water Strider				-	19	19	19	19	19	19	20	20	20	20	20	20	20	20	20
Westmoreland_PPA				-	18	19	19	19	19	19	19	19	19	19	19	19	20	20	20
Whitehouse Solar				19	19	19	19	19	19	19	18	18	18	18	18	18	18	18	18
Woodland Solar				19	19	19	19	19	19	19	18	18	18	18	18	18	18	18	18
Yorktown 3	78	74	71	74	81	81	81	100	-	-	-	-	-	-	-	-	-	-	-

Note: EAF for intermittent resources shown as a capacity factor.

Appendix 5U – Net Capacity Factor for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 9**
UNIT PERFORMANCE DATA
Net Capacity Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Altavista	61.7	61.3	61.0	40.4	53.5	73.0	40.8	5.0	6.4	6.8	6.0	6.3	-	-	-	-	-	-	-
Bath County 1-6	14.2	15.5	12.2	9.6	10.9	10.6	10.5	11.1	10.3	10.0	8.9	8.3	7.6	6.4	6.8	6.4	6.6	6.0	6.4
Battery_Gen1				-	-	-	-	-	-	15.4	13.3	13.7	13.0	11.9	11.9	11.5	12.0	12.4	12.1
Battery_Gen2				-	-	-	-	-	-	-	13.3	13.8	13.0	11.8	12.1	11.3	11.8	12.4	12.6
Battery_Gen3				-	-	-	-	-	-	-	-	-	12.7	12.0	12.1	11.3	12.6	12.4	12.9
Battery_Gen4				-	-	-	-	-	-	-	-	-	-	-	-	11.2	11.8	12.4	12.2
Battery_Gen5				-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.9	12.2
Bear Garden	62.1	74.3	65.3	74.2	65.5	75.0	75.2	77.0	75.5	69.4	67.2	65.0	63.9	64.0	56.3	50.2	52.8	43.6	39.2
Brunswick	67.8	70.0	69.1	77.8	77.5	72.9	81.9	80.8	76.8	74.6	71.3	68.8	66.8	67.4	61.5	57.6	62.3	56.9	52.4
Chesapeake CT 1, 4, 6	0.0	0.7	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	43.4	24.1	10.4	13.0	12.9	6.6	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	31.3	22.5	10.6	9.2	7.6	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	89.7	74.4	84.3	65.5	82.4	72.0	81.0	70.5	71.3	63.7	58.7	55.2	51.4	54.3	45.7	40.4	47.7	39.1	32.9
Chesterfield 8	90.2	76.6	74.4	53.0	81.5	72.0	74.2	80.6	68.6	64.4	59.8	57.0	54.7	54.8	48.2	42.3	49.2	42.0	35.5
Clover 1	48.0	38.6	17.3	13.0	13.9	10.1	8.5	8.8	-	-	-	-	-	-	-	-	-	-	-
Clover 2	37.1	37.3	16.1	14.0	13.9	9.1	8.0	8.8	-	-	-	-	-	-	-	-	-	-	-
CVOW - Phase 1 (880MW)				-	-	-	-	-	-	35.3	37.4	39.5	39.4	39.4	39.4	39.5	39.4	39.4	39.4
CVOW - Phase 2 (880MW)				-	-	-	-	-	-	-	35.3	37.4	39.4	39.4	39.4	39.5	39.4	39.4	39.4
CVOW - Phase 3 (880MW)				-	-	-	-	-	-	-	35.3	37.4	39.4	39.4	39.4	39.5	39.4	39.4	39.4
CVOW (Pilot)				-	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8
Darbytown 1	1.9	2.2	2.0	2.7	2.9	2.2	1.9	1.9	1.5	1.3	1.1	1.0	1.0	0.9	0.8	0.6	0.6	0.5	0.5
Darbytown 2	1.8	2.5	2.2	3.5	2.9	2.2	1.4	1.9	1.5	1.3	1.1	1.0	1.0	0.9	0.8	0.6	0.6	0.5	0.5
Darbytown 3	2.7	3.5	1.6	3.5	2.9	2.3	2.1	2.0	1.5	1.3	1.1	1.1	1.0	1.1	0.8	0.6	0.6	0.5	0.5
Darbytown 4	8.7	3.3	2.6	3.5	2.9	2.2	2.0	2.0	1.5	1.3	1.1	1.0	1.0	1.0	0.8	0.6	0.6	0.5	0.5
Elizabeth River 1	3.3	9.1	4.0	1.9	1.6	2.1	2.3	2.3	2.4	2.3	1.7	1.7	0.9	0.8	0.3	0.3	0.3	0.1	0.2
Elizabeth River 2	3.5	8.1	4.6	2.6	1.6	2.1	2.3	2.2	2.4	2.3	1.7	1.5	0.9	0.8	0.3	0.3	0.3	0.1	0.2
Elizabeth River 3	3.2	9.3	1.7	2.6	1.6	2.1	2.3	2.3	2.4	2.3	1.7	1.7	1.1	0.8	0.3	0.3	0.3	0.1	0.1
Gaston Hydro	14.1	24.5	19.1	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Generic Brownfield CT				-	-	-	2.9	3.1	4.5	3.6	2.8	2.2	1.9	1.4	0.5	0.3	0.3	0.3	0.1
Generic Solar PV- (60MW)				-	-	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2
Generic Solar PV PPA Post 2022				-	-	-	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2
Generic Solar PV PPA Pre 2022				-	-	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2
Generic Storage - Battery (Pilot) -14MW				-	-	-	14.3	15.0	14.4	12.7	10.7	9.9	9.0	7.8	8.2	7.6	-	-	-
Generic Storage - Battery (Pilot) -16MW				-	15.0	14.6	14.4	15.0	14.4	12.8	10.7	9.9	9.0	7.8	-	-	-	-	-
Gordonsville 1	14.2	39.7	64.9	55.7	44.5	49.9	35.4	37.2	41.7	34.8	30.1	27.8	23.8	23.8	19.8	17.5	20.4	16.2	12.5
Gordonsville 2	9.6	49.2	61.2	48.1	43.1	48.7	40.6	39.4	40.0	34.0	28.8	27.3	23.6	23.2	19.1	17.0	20.0	16.0	12.3
Gravel Neck 1-2	0.1	0.1	0.0	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	3.6	4.8	4.2	3.9	3.0	3.0	3.0	3.4	4.4	3.1	2.7	2.3	2.0	1.4	1.0	0.4	0.7	0.6	0.5
Gravel Neck 4	0.8	1.5	0.3	4.0	3.0	3.1	3.0	3.6	4.4	3.1	2.7	2.4	2.1	1.5	1.6	0.4	0.9	0.6	0.5
Gravel Neck 5	3.3	2.9	4.6	3.9	3.0	3.1	3.1	3.6	4.4	3.2	2.7	2.3	2.1	1.5	1.4	0.4	0.8	0.6	0.5
Gravel Neck 6	0.6	3.1	1.5	4.0	3.0	3.0	3.0	3.4	4.4	3.1	2.7	2.4	2.1	1.5	1.5	0.4	0.9	0.6	0.5

Appendix 5U cont. – Net Capacity Factor for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 9**
UNIT PERFORMANCE DATA
Net Capacity Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Greensville	-	34.8	70.9	77.0	78.2	76.4	77.6	75.1	76.1	75.9	74.8	72.4	72.0	72.0	67.1	64.6	67.9	65.1	61.6
Hopewell	66.0	68.4	64.0	11.8	35.6	59.9	49.4	4.0	4.4	5.5	4.5	4.7	-	-	-	-	-	-	-
Ladysmith 1	9.4	11.3	11.0	9.8	7.0	8.0	8.3	9.0	8.9	7.1	6.1	5.8	5.6	5.6	4.3	3.9	3.6	4.2	2.3
Ladysmith 2	11.1	22.3	8.5	9.8	7.0	7.9	8.4	8.9	8.9	7.1	6.1	5.8	5.6	5.6	4.3	4.1	3.6	4.0	2.3
Ladysmith 3	5.7	9.0	11.7	9.9	7.3	8.2	8.7	9.1	9.0	7.2	6.4	6.1	5.8	5.8	4.5	4.2	3.9	4.3	2.6
Ladysmith 4	9.4	5.5	13.4	9.6	7.2	8.1	8.8	9.1	9.0	7.1	6.4	6.0	5.8	5.8	4.5	4.1	3.9	4.6	2.6
Ladysmith 5	6.5	3.6	3.3	9.9	7.5	8.1	8.8	9.1	9.0	7.2	6.4	6.1	5.8	5.8	4.5	4.2	4.0	4.3	2.7
Lowmoor CT 1-4	0.1	0.7	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	49.4	43.4	36.8	38.1	41.4	41.1	32.9	32.8	38.5	13.0	11.3	11.7	13.2	15.2	15.0	12.1	10.5	7.4	5.9
Mount Storm 2	58.0	32.2	34.6	38.1	41.4	45.9	39.1	35.4	41.0	13.7	12.3	12.8	14.7	16.3	16.7	13.0	11.5	8.2	6.7
Mount Storm 3	39.1	41.2	25.2	29.4	36.2	32.7	25.7	24.2	32.1	8.3	7.2	7.7	8.5	10.1	8.9	7.0	6.3	4.4	3.6
Mount Storm CT	0.0	0.2	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Pump Storage				-	-	-	-	-	-	-	-	-	-	8.6	8.3	7.9	7.9	7.7	7.7
North Anna 1	102.3	91.1	94.5	96.3	87.8	89.2	96.3	77.8	89.0	96.3	88.9	82.9	96.3	82.9	89.0	96.3	88.9	89.0	96.3
North Anna 2	92.3	101.9	90.4	87.5	96.4	89.2	75.7	96.4	88.9	89.1	96.4	88.9	82.9	96.4	82.9	89.1	88.9	96.4	89.0
North Anna Hydro	29.2	26.2	7.0	29.1	29.0	29.0	29.0	29.1	29.0	29.0	29.0	29.1	29.0	29.0	29.0	29.1	29.0	29.0	29.0
Northern Neck CT 1-4	0.2	0.6	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	0.9	0.8	0.5	6.0	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	59.1	71.2	56.3	57.0	63.5	76.9	78.6	71.8	68.0	63.4	60.8	58.0	56.7	55.0	49.8	46.1	50.1	45.4	39.3
Possum Point CT 1-6	0.1	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	9.9	19.5	6.5	4.7	2.7	3.4	4.0	5.2	6.3	5.1	4.0	3.5	2.9	2.8	2.1	1.7	1.4	0.8	0.8
Remington 2	9.8	16.0	3.8	4.6	2.6	3.4	4.0	5.3	6.3	5.0	4.1	3.5	3.0	2.8	2.0	1.8	1.3	0.8	0.8
Remington 3	10.0	18.8	7.1	5.7	3.2	4.0	4.6	5.6	6.6	5.3	4.3	3.8	3.2	3.1	2.2	1.9	1.4	0.8	0.9
Remington 4	8.6	17.7	4.9	5.6	3.2	3.7	4.9	6.1	7.1	5.5	4.3	3.7	3.1	2.9	2.0	1.8	1.6	0.9	0.8
Roanoke Rapids Hydro	25.7	45.2	36.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5
Rosemary	9.8	2.0	0.2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	-	-	-	-
Scott Solar	20.6	13.7	13.9	19.1	19.0	19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.2	18.1	18.0	17.9	17.8	17.8
Solar Partnership Program	-			13.7	13.7	13.7	13.7	13.7	13.7	13.8	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Solar_DG				-	-	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Southampton	62.5	70.2	59.4	20.9	35.5	61.6	57.1	3.8	4.3	5.5	4.4	4.8	-	-	-	-	-	-	-
Surry 1	102.4	89.4	90.5	95.9	89.2	88.7	95.9	82.9	82.2	95.9	82.8	88.4	95.9	72.5	88.4	-	-	-	-
Surry 2	94.2	90.7	102.6	85.7	88.7	95.9	88.7	82.3	95.9	80.2	82.2	95.9	72.5	88.4	95.9	95.9	-	-	-
US-3 Solar 1	-			19.1	19.1	19.2	19.1	19.1	19.1	19.2	19.1	19.1	19.1	19.2	19.1	19.1	19.1	19.2	19.1
US-3 Solar 2	-			-	19.1	19.2	19.1	19.1	19.1	19.2	19.1	19.1	19.1	19.2	19.1	19.1	19.1	19.2	19.1
US-4 Solar	-			-	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Virginia City Hybrid Energy Center	62.4	55.4	22.2	5.7	6.9	7.5	7.5	8.2	11.4	8.3	7.0	7.3	8.4	9.7	9.0	7.3	6.8	4.8	3.7
Warren	75.7	69.2	73.1	69.5	53.1	67.8	73.9	76.5	74.9	68.0	63.1	59.7	57.7	58.4	53.8	50.8	53.7	45.2	39.4
Water Strider				-	19.0	19.1	19.2	19.3	19.4	19.5	19.6	19.7	19.8	19.9	20.0	20.1	20.2	20.3	20.4
Westmoreland_PPA				-	18.4	18.5	18.6	18.7	18.8	18.9	19.0	19.1	19.2	19.3	19.4	19.5	19.6	19.7	19.8
Whitehouse Solar	19.9	16.2	23.9	19.1	19.0	19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.2	18.1	18.0	17.9	17.8	17.8
Woodland Solar	17.8	19.1	21.6	19.1	19.1	19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.2	18.1	18.0	17.9	17.9	17.8
Yorktown 3	1.1	3.8	0.8	3.0	3.0	3.0	3.0	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 5V – Existing Capacity for Plan B19 (GWh)

Company Name: Virginia Electric and Power Company **Schedule 7**

CAPACITY DATA

	(ACTUAL)			(PROJECTED)															
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. Firm Capacity (MW)(1)																			
a. Nuclear	3,357	3,357	3,357	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349
b. Biomass(3)	183	183	183	205	211	214	214	214	214	214	214	214	61	61	61	61	61	61	61
c. Coal	4,400	4,400	3,654	3,632	3,626	3,623	2,609	2,609	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170
d. Heavy Fuel Oil	1,572	1,572	1,559	1,413	1,413	790	790	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil	596	596	584	234	206	206	-	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	543	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Natural Gas-Combined Cycle	4,948	5,756	6,293	6,304	6,304	6,304	6,304	6,304	6,304	6,304	6,139	6,139	6,139	6,139	6,139	6,139	6,139	6,139	6,139
h. Natural Gas-Turbine	2,053	2,053	2,051	2,408	2,408	2,408	2,882	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367
i. Hydro-Conventional	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
j. Pumped Storage & Battery	1,808	1,808	1,808	1,808	1,815	1,815	1,820	1,820	1,820	1,924	2,054	2,054	2,184	2,484	2,478	2,608	2,602	2,732	2,732
k. Renewable	6	6	6	73	147	367	571	810	1,012	1,628	2,461	2,818	3,137	3,490	3,806	4,120	4,432	5,427	5,654
l. Total Company Firm Capacity	19,782	20,047	19,810	19,741	19,793	19,391	18,855	18,788	18,552	19,271	20,070	20,427	20,723	21,376	21,685	22,129	22,436	23,561	23,788
m. Other (NUG)(4)	238	-	-	-	36	137	260	401	523	719	950	1,130	1,360	1,579	1,778	2,045	2,242	2,425	2,538
n. Total	20,020	20,047	19,810	19,741	19,829	19,528	19,114	19,190	19,075	19,990	21,020	21,557	22,082	22,955	23,463	24,175	24,678	25,987	26,327
II. Firm Capacity Mix (%)(2)																			
a. Nuclear	16.8%	16.7%	16.9%	17.0%	16.9%	17.1%	17.5%	17.4%	17.6%	16.8%	15.9%	15.5%	15.2%	14.6%	14.3%	13.9%	13.6%	12.9%	12.7%
b. Biomass(3)	0.9%	0.9%	0.9%	1.0%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.0%	1.0%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%
c. Coal	22.0%	21.9%	18.4%	18.4%	18.3%	18.6%	13.6%	13.6%	11.4%	10.9%	10.3%	10.1%	9.8%	9.5%	9.2%	9.0%	8.8%	8.4%	8.2%
d. Heavy Fuel Oil	7.9%	7.8%	7.9%	7.2%	7.1%	4.0%	4.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Light Fuel Oil	3.0%	3.0%	2.9%	1.2%	1.0%	1.1%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
g. Natural Gas-Combined Cycle	24.7%	28.7%	31.8%	31.9%	31.8%	32.3%	33.0%	32.9%	33.0%	31.5%	29.2%	28.5%	27.8%	26.7%	26.2%	25.4%	24.9%	23.6%	23.3%
h. Natural Gas-Turbine	10.3%	10.2%	10.4%	12.2%	12.1%	12.3%	15.1%	17.5%	17.7%	16.8%	16.0%	15.6%	15.2%	14.7%	14.4%	13.9%	13.6%	13.0%	12.8%
i. Hydro-Conventional	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.7%	1.6%	1.7%	1.6%	1.5%	1.5%	1.4%	1.4%	1.3%	1.3%	1.3%	1.2%	1.2%
j. Pumped Storage & Battery	9.0%	9.0%	9.1%	9.2%	9.2%	9.3%	9.5%	9.5%	9.5%	9.6%	9.8%	9.5%	9.9%	10.8%	10.6%	10.8%	10.5%	10.5%	10.4%
k. Renewable	0.0%	0.0%	0.0%	0.4%	0.7%	1.9%	3.0%	4.2%	5.3%	8.1%	11.7%	13.1%	14.2%	15.2%	16.2%	17.0%	18.0%	20.9%	21.5%
l. Total Company Firm Capacity	98.8%	100.0%	100.0%	100.0%	99.8%	99.3%	98.6%	97.9%	97.3%	96.4%	95.5%	94.8%	93.8%	93.1%	92.4%	91.5%	90.9%	90.7%	90.4%
m. Other (NUG)(4)	1.2%	0.0%	0.0%	0.0%	0.2%	0.7%	1.4%	2.1%	2.7%	3.6%	4.5%	5.2%	6.2%	6.9%	7.6%	8.5%	9.1%	9.3%	9.6%
n. Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Notes: 1) Net dependable annual firm capability during peak season.
2) Each item in Section I as a percent of line n (Total).
3) Includes current estimates for renewable capacity by VCHEC.
4) Includes 35% Solar DG and 35% energy storage battery.

Appendix 5W – Energy Generation by Type for Plan B19 (GWh)

Company Name: Virginia Electric and Power Company **Schedule 2**

GENERATION

	(ACTUAL)			(PROJECTED)															
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. System Output (GWh)																			
a. Nuclear	28,683	27,361	27,720	27,928	27,601	27,673	27,199	25,925	27,144	27,556	26,691	27,227	26,498	25,923	27,163	28,612	27,722	28,302	28,295
b. Biomass[(1)]	1,163	1,196	1,008	357	594	910	699	102	130	124	105	111	46	53	49	40	37	26	20
c. Coal	15,376	12,302	7,177	6,950	7,556	7,119	5,488	5,292	6,040	2,129	1,864	1,948	2,201	2,525	2,440	1,946	1,725	1,220	978
d. Heavy Fuel Oil	141	313	88	633	383	208	86	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil	131	313	35	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	163	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Natural Gas-Combined Cycle	26,832	28,500	37,219	41,008	39,546	41,531	43,685	43,295	42,139	39,996	38,201	36,741	35,728	35,872	32,683	30,710	32,772	29,431	26,688
h. Natural Gas-Turbine	1,246	1,888	1,168	1,449	1,022	1,128	1,348	1,636	1,845	1,472	1,215	1,086	964	888	618	515	480	461	297
i. Hydro-Conventional	876	1,577	1,311	612	610	610	610	612	610	610	610	612	610	610	610	612	610	610	610
j. Pumped Storage & Battery	2,240	2,453	1,934	1,533	1,742	1,698	1,700	1,809	1,677	1,968	2,117	2,053	2,263	2,207	2,264	2,467	2,552	2,833	2,909
k. Renewable	102	80	90	343	710	1,793	2,788	3,971	4,945	9,341	16,334	18,612	20,411	22,141	23,679	25,296	26,732	36,673	37,780
l. Total Generation	76,953	76,094	77,750	80,813	79,764	82,670	83,604	82,641	84,529	83,196	87,137	88,390	88,721	90,220	89,508	90,198	92,631	99,557	97,577
m. Purchased Power (NUGs)	4,611	4,289	2,616	-	165	664	1,264	1,965	2,553	3,241	4,029	4,924	5,689	6,763	7,733	8,723	9,659	10,212	10,763
n. Purchased Power (Battery Storage)	-	-	-	-	-	-	-	-	-	189	367	380	554	510	517	661	700	904	915
o. Purchased Power (Market / PJM)	10,488	14,537	13,552	4,814	7,239	6,671	7,620	10,147	7,444	9,948	7,742	7,352	8,206	7,833	8,498	8,937	7,923	4,794	6,800
p. Total Payback Energy[(2)]				8	9	12	16	19	22	24	25	24	23	23	23	23	23	23	24
q. Less Pumping Energy	(3,014)	(3,043)	(2,801)	(1,916)	(2,177)	(2,104)	(2,139)	(2,264)	(2,086)	(2,644)	(3,025)	(2,963)	(3,425)	(3,282)	(3,340)	(3,755)	(3,913)	(4,487)	(4,601)
r. Less Other Sales[(3)]	(1,680)	(225)	(561)	(2,201)	(1,612)	(2,069)	(1,957)	(2,149)	(1,478)	(2,376)	(4,051)	(4,838)	(5,699)	(7,206)	(7,236)	(8,012)	(9,561)	(12,550)	(11,914)
s. Total System Firm Energy Req.	87,359	91,652	90,556	81,510	83,379	85,832	88,392	90,340	90,962	91,554	92,200	93,244	94,047	94,838	95,680	96,752	97,440	98,431	99,540
II. Energy Supplied by Competitive Service Providers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Notes: (1) Includes current estimates for renewable energy generation by VCHEC.
(2) Payback energy is accounted for in Total Generation.
(3) Includes all sales or delivery transactions with other electric utilities (*e.g.*, firm or economy sales).

Appendix 5X – Energy Generation by Type for Plan B19 (%)

Company Name: Virginia Electric and Power Company

Schedule 3

GENERATION

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
III. System Output Mix (%)																			
a. Nuclear	32.8%	29.9%	30.6%	34.3%	33.1%	32.2%	30.8%	28.7%	29.8%	30.1%	28.9%	29.2%	28.2%	27.3%	28.4%	29.6%	28.5%	28.8%	28.4%
b. Biomass(1)	1.3%	1.3%	1.1%	0.4%	0.7%	1.1%	0.8%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
c. Coal	17.6%	13.4%	7.9%	8.5%	9.1%	8.3%	6.2%	5.9%	6.6%	2.3%	2.0%	2.1%	2.3%	2.7%	2.6%	2.0%	1.8%	1.2%	1.0%
d. Heavy Fuel Oil	0.2%	0.3%	0.1%	0.8%	0.5%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Light Fuel Oil	0.2%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
g. Natural Gas-Combined Cycle	30.7%	31.1%	41.1%	50.3%	47.4%	48.4%	49.4%	47.9%	46.3%	43.7%	41.4%	39.4%	38.0%	37.8%	34.2%	31.7%	33.6%	29.9%	26.8%
h. Natural Gas-Turbine	1.4%	2.1%	1.3%	1.8%	1.2%	1.3%	1.5%	1.8%	2.0%	1.6%	1.3%	1.2%	1.0%	0.9%	0.6%	0.5%	0.5%	0.5%	0.3%
i. Hydro-Conventional	1.0%	1.7%	1.4%	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
j. Pumped Storage & Battery	2.6%	2.7%	2.1%	1.9%	2.1%	2.0%	1.9%	2.0%	1.8%	2.1%	2.3%	2.2%	2.4%	2.3%	2.4%	2.6%	2.6%	2.9%	2.9%
k. Renewable	0.1%	0.1%	0.1%	0.4%	0.9%	2.1%	3.2%	4.4%	5.4%	10.2%	17.7%	20.0%	21.7%	23.3%	24.7%	26.1%	27.4%	37.3%	38.0%
l. Total Generation	88.1%	83.0%	85.9%	99.1%	95.7%	96.3%	94.6%	91.5%	92.9%	90.9%	94.5%	94.8%	94.3%	95.1%	93.5%	93.2%	95.1%	101.1%	98.0%
m. Purchased Power (NUGs)	5.3%	4.7%	2.9%	0.0%	0.2%	0.8%	1.4%	2.2%	2.8%	3.5%	4.4%	5.3%	6.0%	7.1%	8.1%	9.0%	9.9%	10.4%	10.8%
n. Purchased Power (Battery Storage)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.4%	0.4%	0.6%	0.5%	0.5%	0.7%	0.7%	0.9%	0.9%
o. Purchased Power (Market / PJM)	12.0%	15.9%	15.0%	5.9%	8.7%	7.8%	8.6%	11.2%	8.2%	10.9%	8.4%	7.9%	8.7%	8.3%	8.9%	9.2%	8.1%	4.9%	6.8%
p. Total Payback Energy(2)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
q. Less Pumping Energy	-3.5%	-3.3%	-3.1%	-2.4%	-2.6%	-2.5%	-2.4%	-2.5%	-2.3%	-2.9%	-3.3%	-3.2%	-3.6%	-3.5%	-3.5%	-3.9%	-4.0%	-4.6%	-4.6%
r. Less Other Sales(3)	-1.9%	-0.2%	-0.6%	-2.7%	-1.9%	-2.4%	-2.2%	-2.4%	-1.6%	-2.6%	-4.4%	-5.2%	-6.1%	-7.6%	-7.6%	-8.3%	-9.8%	-12.8%	-12.0%
s. Total System Firm Energy Req.	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IV. System Load Factor	57.7%	56.6%	59.0%	60.6%	61.3%	61.0%	61.3%	61.8%	61.6%	61.9%	62.4%	61.8%	61.9%	62.5%	62.1%	62.2%	61.9%	62.0%	62.1%

Notes: (1) Includes current estimates for renewable energy generation by VCHEC.
(2) Payback energy is accounted for in Total Generation.
(3) Includes all sales or delivery transactions with other electric utilities *(e.g.*, firm or economy sales).

Appendix 5Y – Renewable Resources for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 11**

RENEWABLE RESOURCE GENERATION (GWh)

							(ACTUAL)				(PROJECTED)														
Resource Type[1]	**Unit Name**	**State**	**C.O.D.[2]**	**Build / Purchase / Convert[3]**	**Life/ Duration[4]**	**Size MW[5]**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Hydro																									
	Gaston Hydro	NC	Feb-63	Build	60	220	271	472	368	321	320	320	320	321	320	320	320	321	320	320	320	321	320	320	320
	North Anna Hydro	VA	Dec-87	Build	60	1	3	2	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Roanoke Rapids Hydro	NC	Sep-55	Build	60	95	211	376	303	288	287	287	287	288	287	287	287	288	287	287	287	288	287	287	287
Sub-total: NC						315	482	848	671	609	607	607	607	609	607	607	607	609	607	607	607	609	607	607	607
Sub-total: VA						1	3	2	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Sub-total: Hydro						316	484	850	672	612	610	610	610	612	610	610	610	612	610	610	610	612	610	610	610
Solar																									
	Solar Partnership Program	VA	2013-2017	Build	20	7	10	4	4	9	9	9	9	9	9	9	9	9	9	9	9	9	9	8	8
	Existing NC Solar NUGs	NC					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Existing VA Solar NUGs	VA	2020-2021	Purchase	20		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Scott Solar	VA	Dec-2016	Build	35	17	31	21	21	29	29	29	29	29	28	28	28	28	28	28	28	27	27	27	27
	Whitehouse Solar	VA	Dec-2016	Build	35	19	28	32	32	34	33	33	33	33	33	33	32	32	32	32	32	32	31	31	31
	Woodland Solar	VA	Dec-2016	Build	35	20	33	33	33	32	32	32	32	32	31	31	31	31	31	31	30	30	30	30	30
	US-3 Solar 1	VA	2020	Build	35	142	-	-	6	239	238	237	235	235	233	232	231	230	228	227	226	225	224	223	221
	US-3 Solar 2	VA	2021	Build	35	98	-	-	-	-	164	163	162	162	161	160	159	159	158	157	156	156	154	154	153
	US-4 Solar	VA	2021	Build	36	100	-	-	-	-	162	161	160	160	159	158	157	156	155	155	154	153	152	151	151
	Water Strider	VA	2021	Purchase	35	80	-	-	-	-	133	133	133	133	133	133	133	133	133	133	132	133	132	132	132
	Westmoreland_PPA	VA	2021	Purchase	35	20	-	-	-	-	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
	Generic Solar PV_PPA	VA	2021-2035	Purchase	35	6,625	-	-	-	-	-	500	1,100	1,799	2,388	3,076	3,864	4,759	5,525	6,598	7,569	8,558	9,494	10,048	10,599
	Generic Solar PV	VA	2021-2035	Build	35	12,175	-	-	-	-	-	1,086	2,084	3,269	4,247	6,014	7,590	9,366	10,899	12,632	14,174	15,752	17,234	18,350	19,460
Sub-total: NC						0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total: VA						19,303	103	90	96	343	832	2,414	4,009	5,891	7,453	9,906	12,266	14,935	17,229	20,033	22,542	25,107	27,520	29,187	30,845
Sub-total: Solar						19,303	103	90	96	343	832	2,414	4,009	5,891	7,453	9,906	12,266	14,935	17,229	20,033	22,542	25,107	27,520	29,187	30,845
Wind																									
	CVOW (Pilot)	VA	Jan-21	Build	20	12	-	-	-	-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
	Generic Wind		2021-2035	Build	20	5,112	-	-	-	-	-	-	-	-	-	2,633	8,053	8,557	8,827	8,827	8,827	8,868	8,827	17,655	17,655
Sub-total: NC						0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total: VA						5,124	-	-	-	-	44	44	44	44	44	2,676	8,097	8,601	8,871	8,871	8,871	8,912	8,871	17,698	17,698
Sub-total: Wind						5124	-	-	-	-	44	44	44	44	44	2,676	8,097	8,601	8,871	8,871	8,871	8,912	8,871	17,698	17,698
Total Renewables: NC						315	482	848	671	609	607	607	607	609	607	607	607	609	607	607	607	609	607	607	607
Total Renewables: VA						24,428	105	92	97	346	878	2,460	4,055	5,938	7,500	12,585	20,365	23,538	26,103	28,906	31,415	34,022	36,394	46,888	48,545
Total Renewables						24,743	587	940	768	955	1,485	3,067	4,662	6,547	8,107	13,192	20,972	24,148	26,710	29,514	32,022	34,631	37,001	47,495	49,153

Notes: (1) Per definition in Va. Code § 56-576.
(2) Commercial operation date.
(3) Company built, purchased, or converted.
(4) Expected life of facility or duration of purchase contract.
(5) Net summer capacity for hydro, nameplate for solar and wind.

Appendix 5Z – Potential Supply-Side Resources for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 15b**
UNIT PERFORMANCE DATA
Potential Supply-Side Resources (MW)

Unit Name	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Annual Firm	MW Nameplate
Battery Pilot	Storage		2021	6	16
US-3 Solar 2	Intermittent	Solar	2021	34	98
US-4 Solar 1	Intermittent	Solar	2021	34	100
CVOW	Intermittent	Wind	2021	4	12
Solar 2022	Intermittent	Solar	2022	319	1,000
Battery Pilot	Storage		2023	6	14
Solar 2023	Intermittent	Solar	2023	330	960
Generic CT	Peak	Natural Gas	2023	485	485
Solar 2024	Intermittent	Solar	2024	381	1,180
Generic CT	Peak	Natural Gas	2024	458	458
Solar 2025	Intermittent	Solar	2025	330	960
Generic Battery	Storage		2026	160	400
Solar 2026	Intermittent	Solar	2026	505	1,540
CVOW - Phase 1	Intermittent	Wind	2026	256	852
Generic Battery	Storage		2027	200	500
Solar 2027	Intermittent	Solar	2027	495	1,440
CVOW - Phase 2-3	Intermittent	Wind	2027	511	1,704
Solar 2028	Intermittent	Solar	2028	546	1,660
Generic Battery	Storage		2029	200	500
Solar 2029	Intermittent	Solar	2029	495	1,440
Pump Storage	Storage		2029	300	300
Solar 2030	Intermittent	Solar	2030	587	1,780
Solar 2031	Intermittent	Solar	2031	537	1,560
Generic Battery	Storage		2032	200	500
Solar 2032	Intermittent	Solar	2032	537	1,560
Solar 2033	Intermittent	Solar	2033	537	1,560
Generic Battery	Storage		2034	200	500
Solar 2034	Intermittent	Solar	2034	372	1,080
Generic Offshore Wind	Intermittent	Wind	2034	767	2,556
Solar 2035	Intermittent	Solar	2035	372	1,080

Note: (1) Estimated commercial operation date.

Appendix 5AA – Summer Capacity Position for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 16**

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Existing Capacity																			
Conventional	17,620	17,173	17,681	17,544	17,516	16,893	15,662	14,872	14,434	14,434	14,269	14,269	14,116	14,116	14,116	14,116	14,116	14,116	14,116
Renewable NC	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
Renewable VA	58	58	58	74	74	73	73	73	73	72	72	72	72	71	71	71	71	70	70
Renewable	373	373	373	389	389	388	388	388	388	387	387	387	387	386	386	386	386	385	385
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	1,809	1,809	1,809	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808
Storage	1,809	1,809	1,809	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808
Total Existing Capacity	19,802	19,355	19,863	19,741	19,713	19,090	17,859	17,068	16,630	16,629	16,464	16,464	16,310	16,310	16,310	16,310	16,309	16,309	16,309
Generation Under Construction																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	74	74	73	73	73	72	72	72	71	71	70	70	70	69	69
Renewable	-	-	-	-	74	74	73	73	73	72	72	72	71	71	70	70	70	69	69
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-
Storage	-	-	-	-	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-
Total Planned Construction Capacity	-	-	-	-	80	80	80	79	79	79	78	78	78	77	70	70	70	69	69
Generation Under Development																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Development Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Potential (Expected) New Capacity																			
Conventional	-	-	-	-	-	-	485	970	970	970	970	970	970	970	970	970	970	970	970
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	-	221	426	665	868	1,484	2,318	2,676	2,995	3,349	3,665	3,980	4,293	5,289	5,516
Renewable	-	-	-	-	-	221	426	665	868	1,484	2,318	2,676	2,995	3,349	3,665	3,980	4,293	5,289	5,516
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	6	6	6	110	240	240	370	670	670	800	794	924	924
Storage	-	-	-	-	-	-	6	6	6	110	240	240	370	670	670	800	794	924	924
Total Potential New Capacity	-	-	-	-	-	221	916	1,641	1,843	2,564	3,528	3,885	4,335	4,989	5,305	5,749	6,057	7,183	7,410
Other (NUG)																			
Conventional	238	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	36	137	260	401	523	663	824	1,004	1,164	1,383	1,582	1,779	1,976	2,089	2,202
Renewable	-	-	-	-	36	137	260	401	523	663	824	1,004	1,164	1,383	1,582	1,779	1,976	2,089	2,202
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	-	56	126	126	196	196	196	266	266	336	336
Storage	-	-	-	-	-	-	-	-	-	56	126	126	196	196	196	266	266	336	336
Total Other (NUG) Capacity	238	-	-	-	36	137	260	401	523	719	950	1,130	1,360	1,579	1,778	2,045	2,242	2,425	2,538
Unforced Availability	-	-																	
Net Generation Capacity	20,040	19,355	19,863	19,741	19,829	19,528	19,114	19,190	19,075	19,990	21,020	21,557	22,082	22,955	23,463	24,175	24,678	25,987	26,327
Existing DSM Reductions																			
Demand Response	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Conservation/Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing DSM Reductions[1]	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Approved DSM Reductions																			
Demand Response[3]	69	58	55	63	63	64	64	65	65	65	65	66	66	66	66	66	66	66	66
Conservation/Efficiency[2][3]	109	122	135	129	125	127	136	134	122	113	105	102	101	99	97	95	93	92	93
Total Approved DSM Reductions	178	180	190	191	188	191	201	199	188	179	171	167	167	165	163	160	159	158	158
Proposed DSM Reductions																			
Demand Response[3]	-	-	-	7	27	47	63	77	83	84	85	86	87	88	89	89	90	91	92
Conservation/Efficiency[2]	-	-	-	16	26	45	66	88	114	124	124	124	124	128	129	129	129	129	133
Total Proposed DSM Reductions	-	-	-	23	53	92	129	165	197	208	209	210	211	216	217	218	219	219	224
Unidentified DSM Reductions																			
Demand Response[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conservation/Efficiency[2]	-	-	-	-	39	87	143	209	276	335	447	408	388	409	422	474	377	358	340
Total Proposed DSM Reductions	-	-	-	-	39	87	143	209	276	335	447	408	388	409	422	474	377	358	340
Total Demand-Side Reductions[1]	180	182	192	216	282	372	475	575	663	724	829	787	768	792	804	854	757	738	725
Net Generation & Demand-side	20,220	19,537	20,055	19,957	20,110	19,900	19,589	19,765	19,738	20,714	21,849	22,344	22,850	23,747	24,267	25,029	25,435	26,724	27,051
Capacity Requirement or PJM Capacity Obligation	19,769	20,548	20,251	20,022	20,218	19,800	20,150	20,396	20,327	20,599	20,596	20,927	21,050	21,219	21,219	21,472	21,818	21,963	22,114
Net Utility Capacity Position	452	(1,010)	(196)	(65)	(107)	99	(560)	(632)	(589)	115	1,253	1,416	1,800	2,528	3,048	3,557	3,617	4,761	4,937

Notes: (1) Existing DSM programs are included in the load forecast.
(2) Efficiency programs are not part of the Company's calculation of capacity.
(3) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

Appendix 5AB – Capacity Position for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 4**

POWER SUPPLY DATA

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. Capability (MW)																			
1. Summer																			
a. Firm Capacity Capacity[1]	19,802	19,355	19,863	19,741	19,793	19,391	18,855	18,788	18,552	19,271	20,070	20,427	20,723	21,376	21,685	22,129	22,436	23,561	23,788
b. Positive Interchange Commitments[2]	238	-	-	-	36	137	260	401	523	719	950	1,130	1,360	1,579	1,778	2,045	2,242	2,425	2,538
c. Capability in Cold Reserve/ Reserve Shutdown Status[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response - Existing	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
e. Demand Response - Approved[5]	69	58	55	63	63	64	64	65	65	65	65	66	66	66	66	66	66	66	66
f. Demand Response - Future[5]	-	-	-	7	27	47	63	77	83	84	85	86	87	88	89	89	90	91	92
g. Total Net Summer Capability[4]	20,109	19,413	19,918	19,809	19,917	19,637	19,240	19,330	19,221	20,138	21,169	21,706	22,233	23,106	23,615	24,328	24,832	26,141	26,482
2. Winter																			
a. Firm Capacity Capacity[1]	19,802	19,355	19,863	20,824	20,796	20,176	19,366	19,099	18,660	19,023	19,502	19,505	19,485	19,788	19,784	19,917	19,914	20,813	20,815
b. Positive Interchange Commitments[2]	238	-	-	-	0	1	2	3	5	62	133	135	206	208	210	282	283	354	355
c. Capability in Cold Reserve/ Reserve Shutdown Status[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response[5]	6	6	6	16	37	58	76	92	100	102	103	104	105	106	107	108	109	110	111
e. Demand Response-Existing[3]	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
f. Total Net Winter Capability[4]	20,046	19,361	19,869	20,840	20,833	20,235	19,444	19,194	18,765	19,187	19,739	19,744	19,796	20,102	20,101	20,307	20,306	21,277	21,281

Notes: (1) Net seasonal capability.
(2) Does not include firm commitments from existing NUGs and estimated solar NUGs.
(3) Included in the winter capacity forecast.
(4) Does not include behind-the-meter generation MW.
(5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity. Values reflective of free-ridership.

Appendix 5AC – Construction Forecast for Plan B19

Company Name: Virginia Electric and Power Company **Schedule 17**

CONSTRUCTION COST FORECAST (Thousand Dollars)

(PROJECTED)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
I. New Traditional Generating Facilities																
a. Construction Expenditures (non-AFUDC)	319,804	326,223	518,290	644,848	436,991	312,115	385,020	381,492	249,784	248,810	216,379	59,406	90	-	-	-
b. AFUDC	674	2,036	3,816	5,129	5,953	7,532	9,001	10,617	11,948	12,999	13,979	6,116	6,241	-	-	-
c. Annual Total	320,478	328,259	522,106	649,976	442,944	319,647	394,021	392,109	261,732	261,809	230,358	65,522	6,331	-	-	-
d. Cumulative Total	320,478	648,736	1,170,843	1,820,819	2,263,763	2,583,411	2,977,432	3,369,541	3,631,273	3,893,083	4,123,441	4,188,962	4,195,293	4,195,293	4,195,293	4,195,293
II. New Renewable Generating Facilities																
a. Construction Expenditures (non-AFUDC)	1,373,964	986,242	1,510,731	1,889,911	3,519,579	4,088,927	3,316,934	2,178,931	1,877,687	1,887,699	2,390,729	2,035,973	3,657,409	4,534,938	1,852,148	688,303
b. AFUDC	3,619	6,815	8,220	11,287	18,516	21,249	18,015	11,488	12,024	12,967	14,870	16,964	22,024	32,226	5,469	1,451
c. Annual Total	1,377,583	993,057	1,518,951	1,901,198	3,538,095	4,110,176	3,334,949	2,190,419	1,889,711	1,900,666	2,405,599	2,052,936	3,679,434	4,567,164	1,857,617	689,754
d. Cumulative Total	1,377,583	2,370,640	3,889,592	5,790,790	9,328,885	13,439,061	16,774,010	18,964,429	20,854,140	22,754,806	25,160,405	27,213,341	30,892,775	35,459,939	37,317,556	38,007,310
III. New Storage Facilities																
a. Construction Expenditures (non-AFUDC)	80,059	31,873	48,798	40,065	773,117	1,082,325	1,076,455	569,975	1,251,422	147,334	56,572	851,006	-	882,437	-	732,024
b. AFUDC	169	265	435	491	2,206	6,810	8,975	8,287	13,041	11,677	-	2,760	-	2,862	-	2,374
c. Annual Total	80,227	32,138	49,234	40,556	775,323	1,089,135	1,085,430	578,261	1,264,463	159,011	56,572	853,765	-	885,299	-	734,398
d. Cumulative Total	80,227	112,365	161,599	202,156	977,478	2,066,613	3,152,043	3,730,304	4,994,767	5,153,778	5,210,350	6,064,115	6,064,115	6,949,414	6,949,414	7,683,812
IV. Other Facilities																
a. Transmission	921	885	885	723	751	751	751	751	751	751	751	751	751	751	751	751
b. Distribution	1,134	1,250	1,408	1,350	1,248	1,129	1,121	1,118	1,115	831	831	831	831	831	831	831
c. Energy Conservation & DR	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Other																
e. AFUDC	44	56	50	45	47	47	47	47	47	47	47	47	47	47	47	47
f. Annual Total	2,116	2,191	2,344	2,117	2,046	1,926	1,919	1,915	1,913	1,629	1,629	1,629	1,629	1,629	1,629	1,629
g. Cumulative Total	2,116	4,307	6,650	8,768	10,814	12,740	14,659	16,574	18,486	20,115	21,744	23,372	25,001	26,630	28,258	29,887
V. Total Construction Expenditures																
a. Annual	1,780,404	1,355,645	2,092,635	2,593,848	4,758,407	5,520,884	4,816,319	3,162,705	3,417,818	2,323,115	2,694,158	2,973,852	3,687,393	5,454,092	1,859,246	1,425,781
b. Cumulative	1,780,404	3,136,049	5,228,684	7,822,533	12,580,940	18,101,824	22,918,143	26,080,848	29,498,667	31,821,781	34,515,940	37,489,791	41,177,184	46,631,276	48,490,522	49,916,302
VI. % of Funds for Total Construction Provided from External Financing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A