COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PREFILED STAFF TESTIMONY

VIRGINIA ELECTRIC AND POWER COMPANY

In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq.*

Volume I

PUBLIC VERSION

Case No. PUR-2018-00065

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PART A

Summary of the Testimony of Gregory L. Abbott

My testimony addresses Virginia Electric and Power Company's (Company") Integrated Resource Plan ("2018 IRP"). Specifically, my testimony:

- Evaluates the 2018 IRP in the context of the Commission's directive in its Order in Case No. PUR-2017-00051 ("2017 IRP Order") that the 2018 IRP include detailed plans to implement the mandates contained in the 2018 Grid Transformation and Security Act ("GTSA");
- Evaluates the Company's identified least cost plan and presents Staff's least cost plan with a calculation of the incremental costs of the GTSA;
- Identifies various concerns and issues with the assumptions used in the Company's modeling runs;
- Addresses the Company's model runs to evaluate solar resources, $870 million of spending on energy efficiency programs under the GTSA, and compliance with the Regional Greenhouse Gas Initiative ("RGGI"); and
- Discusses the Company's rate impact analysis and Short-Term Action Plan.

The Company assumes that the solar resources have a capacity factor of 26%. However, actual observed utility-specific data over the last five years (2013-2017) for the Company's owned and operated solar resources in Virginia show an actual capacity factor of 19.4%. This trend has continued in 2018 with solar resources experiencing an average capacity factor through July 2018 of 19.7%.

The Company unexpectedly decided not to include the natural gas-fired 3X1 combined cycle unit as an available resource option for the model to select. These state-of-the-art units are the least-cost natural gas option by far and Staff strongly disagrees with the Company's decision to eliminate this resource option from its modeling runs.

Staff estimates that the incremental net present value ("NPV") cost of the GTSA compared to Staff's least cost plan, exclusive of the Transmission Pilot, is $5.57 billion.

The NPV cost for Staff's least-cost plan discussed above is based on the Company's load forecast rather than either of Staff's lower load forecasts. This cost may continue to be overstated to the extent the model selects additional unnecessary resources (costs) due to the Company's inflated load forecast. As such, the incremental NPV cost of $5.57 billion for the GTSA compared to Staff's least cost plan may also be understated.

Given the issues identified by Staff in the 2018 IRP, Staff recommends that any certificate of public convenience and necessity ("CPCN") application that relies on the 2018 IRP load forecast, energy sales forecast, and the 2018 IRP PLEXOS model results not be considered adequate for evaluating the CPCN.

Staff recommends that all future IRPs and CPCN filings include an alternative load forecast based on the PJM-derived load forecast method described by Staff witness White in addition to the Company's preferred load forecast. In addition, Staff recommends that future IRPs and CPCN filings include an alternative set of model runs based on the alternative PJM-derived load forecast that also uses actual historic utility-specific capacity factors for solar and/or wind resources. Further, Staff recommends that future CPCN filings include a cost-benefit analysis based on the alternative PJM-derived load forecast. Additionally, such analysis should also use actual updated historic utility-specific capacity factors for solar and/or wind resources in addition to the cost-benefit method based on the Company's preferred load forecast and projected capacity factors.

The Company's 2018 IRP energy sales forecast for the end of the planning period in 2033 is approximately 18,659 gigawatt-hours, or 22% higher than Staff witness McBride's independent energy sales forecast. If the Company had used Staff witness McBride's energy sales forecast in the RGGI modeling runs, it is likely that a much different result would have been obtained and that the cost of compliance with RGGI would be lower than the Company's estimates.

The Company has plans to build 15,024 MW of capacity resources over the 15-year planning period. This compares to the Company's noncoincident peak of 16,350 MW and the coincident peak of 15,698 MW experienced in 2017. In other words, the Company's build plan is nearly equal to its existing coincident peak load. This includes 2,000 MW of offshore wind which was not included in the 2018 IRP. Staff notes that subsequent to filing the 2018 IRP, the Company filed an application for a prudency review for the Coastal Virginia Offshore Wind ("CVOW") demonstration project. In that case, the Company indicated that it will pursue a much larger roll-out (2,000 MW) of utility-scale offshore wind, beginning in 2024, if the demonstration project shows it to be economic.

If the CVOW demonstration project proves that utility-scale offshore wind is economic compared to solar, then it may make sense to get the results of the CVOW demonstration project before deploying a large amount of solar.

Based on the Company's 2013 IRP data and 2018 IRP data, the costs of solar have decreased substantially from 2013 to 2018. By delaying deployment of 5,000 MW of solar from 2013 to 2018, a total estimated cost savings of $10.6 billion was realized from just a five-year delay. The percentage cost decrease exceeded the value of any investment tax credit that would have been realized. Thus, based on history, it may make sense to take a more cautious approach in order to take advantage of the continuing decline in the costs of solar.

PUBLIC VERSION

PREFILED TESTIMONY
OF
GREGORY L. ABBOTT

VIRGINIA ELECTRIC AND POWER COMPANY'S INTEGRATED RESOURCE PLAN FILING

CASE NO. PUR-2018-00065

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE VIRGINIA STATE CORPORATION COMMISSION ("COMMISSION").

A1. My name is Gregory L. Abbott. I am an Associate Deputy Director in the Commission's Division of Public Utility Regulation.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. My testimony addresses Virginia Electric and Power Company's ("DEV" or "Company") 2018 Integrated Resource Plan ("2018 IRP"). Specifically, my testimony:

- Evaluates the IRP in the context of the Commission's directive in its Order in Case No. PUR-2017-00051 ("2017 IRP Order") that the 2018 IRP include detailed plans to implement the mandates contained in the 2018 Grid Transformation and Security Act ("GTSA");
- Evaluates the Company's identified least cost plan and presents Staff's least cost plan with a calculation of the incremental costs of the GTSA;
- Identifies various concerns and issues with the assumptions used in the Company's modeling runs;
- Addresses the Company's model runs to evaluate solar resources, $870 million of spending on energy efficiency programs under the GTSA, and compliance with the Regional Greenhouse Gas Initiative ("RGGI"); and

- Discusses the Company's rate impact analysis and Short-Term Action Plan ("STAP").

Q3. WHAT SPECIFICALLY DID THE COMMISSION DIRECT IN THE 2017 IRP ORDER?

A3. First, the Commission took judicial notice that the 2018 Regular Session of the General Assembly passed and the Governor signed the GTSA. The Commission then directed "that Dominion's future IRPs, beginning with the IRP due to be filed on May 1, 2018, shall include detailed plans to implement the mandates contained in that legislation, as well as plans that comply with all other legal requirements."[1] The Commission further noted that "[t]his includes, for example, the utility's least-cost plan along with plans compliant with proposed federal carbon-control regulations, which are required in accordance with the provisions of both Code § 56-585.1:1 F 1, and Code § 56-599 B 9 . . . ."[2]

Q4. DO YOU HAVE ANY GENERAL COMMENTS?

A4. Yes. Prior to the passage of the GTSA, the Company was required to file its IRP on an annual basis. Pursuant to the GTSA, future IRP filings will occur on a three-year cycle corresponding to the years prior to the Company's Triennial Review filings. The IRP forms the foundation that the Company relies on to support various other filings in the intervening years, such as requests for approval of new generation resources. Given that IRPs will now be filed less frequently, and given the fact that a number of issues and concerns arose out of the 2017 IRP hearing,

[1] 2017 IRP Order at 3-4.
[2] *Id.* at n.8.

particularly related to the Company's load forecast, Staff retained a third-party consultant to perform various independent commodity and load forecasts related to the 2018 IRP to better inform the Commission on the efficacy of the Company's 2018 IRP and its underlying assumptions.

<u>GRID TRANSFORMATION AND SECURITY ACT</u>

Q5. DID THE COMPANY'S 2018 IRP PROVIDE ANY ANALYSIS OF THE POTENTIAL IMPACTS OF THE GTSA ON THE COMPANY'S FUTURE RESOURCE PLANS?

A5. Yes, in part. As filed, the 2018 IRP did model some of the mandates contained in the GTSA. Further, in response to Staff's discovery, the Company modeled additional aspects of the GTSA. However, as will be discussed in my testimony, the Company was not fully responsive in modeling all of the mandates contained in the GTSA. Each of the various mandates contained in the GTSA and the Company's treatment of each in the 2018 IRP is described below:

- <u>16 MW Offshore Wind Demonstration Project</u>: The Company included the 12 MW Coastal Virginia Offshore Wind ("CVOW") demonstration facility in all plans as a locked-in must-run resource.

- <u>5,000 MW of wind/solar</u>: The Company's plans included solar photovoltaic ("PV") resources ranging from 4,720 MW to 6,640 MW which the model selected as economic based on the Company's modeling inputs and assumptions.

- <u>$870 million of Energy Efficiency Programs</u>: The Company did not include $870 million of energy efficiency programs in its 2018 IRP, as filed. However, the Company did provide model runs in response to Staff discovery.

- <u>30 MW Battery Storage Pilot</u>: The Company did not include a 30 MW Battery Storage Pilot in its 2018 IRP, as filed. However, the Company did provide model runs in response to Staff discovery.

- 25% of 5,000 MW of wind/solar from non-utility sources: The Company did not include this requirement in its 2018 IRP. All solar resources contained in each of the plans are self-build resources.

- Strategic Undergrounding Program ("SUP"): The Company did not model SUP spending and the NPV costs of the SUP are not included in the PLEXOS model runs. However, the SUP is assumed to be a common element of each of the plans and therefore, there are no incremental costs associated with the SUP. Also, the SUP will not impact unit dispatch in the Company's model runs because it is a distribution related cost.

- Grid Transformation Plan: The Company did not model the Grid Transformation Plan costs and the NPV costs of the Grid Transformation Plan are not included in the PLEXOS model runs. However, the Grid Transformation Plan is assumed to be a common element of each of the plans and therefore, there are no incremental costs associated with the Grid Transformation Plan. Also, the Grid Transformation Plan will not impact unit dispatch in the Company's model runs because it is a distribution related cost.

- Transmission Line Undergrounding Pilot ("Transmission Pilot"): The Company did not model the Transmission Pilot costs and the NPV costs of the Transmission Pilot are not included in the PLEXOS model runs. However, the Transmission Pilot is assumed to be a common element of each of the plans and therefore, there are no incremental costs associated with the Transmission Pilot. Also, the Transmission Pilot will not impact unit dispatch in the Company's model runs because it is a transmission related cost.

LEAST-COST PLAN

Q6. DID THE COMPANY IDENTIFY A LEAST-COST PLAN AS DIRECTED BY THE COMMISSION IN THE 2017 IRP ORDER?

A6. Yes, the Company identifies Plan A as its least-cost plan.

Q7. DOES STAFF AGREE THAT THE COMPANY'S PLAN A IS THE LEAST-COST PLAN?

A7. No. As discussed by Staff witnesses Samuel and White, there are two major concerns Staff has relative to the Company's modeling inputs and assumptions that impact the least-cost plan.[3]

First, the Company assumes that the solar resources have a capacity factor of 26%.[4] However, actual observed utility-specific data over the last five years (2013-2017) for the Company's owned and operated solar resources in Virginia show an actual capacity factor of 19.4%. Further, third-party contract solar facilities dispatched by the Company, which are predominately located in North Carolina, have experienced an actual capacity factor of 20.3%.[5]

The second major issue relative to DEV's modeling is that the Company unexpectedly decided not to include the natural gas-fired 3X1 combined cycle ("CC") unit as an available resource option for the model to select. These state-of-the-art units are the least-cost natural gas option by far and Staff strongly disagrees with the Company's decision to eliminate this resource option from its modeling runs, particularly given that the 2017 IRP Order directed the Company to identify the least-cost plan.

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[3] In addition, the Company included the CVOW project as a locked-in must-run resource in Plan A which is at odds with identifying the least-cost plan.

[4] The Company's response to Staff Interrogatory No. 6-91 indicated that the Company relied on projections submitted by the Engineering, Procurement and Construction contractors from the Company's Whitehouse Solar and Remington Solar projects.

[5] Staff requested updated capacity factor data for January through July of 2018 in Staff Interrogatory No. 13-142. The Company's response shows that the Company's owned and operated solar resources in Virginia had a capacity factor of 19.7% and the third-party contract solar facilities dispatched by the Company has a capacity factor of 20.4%.

To better identify a true least-cost plan, Staff requested that the Company re-simulate Plan A with the following changes: (i) using a 20%[6] capacity factor for solar resources; (ii) making the natural gas-fired 3X1 CC unit available to be selected by the model; and (iii) not locking in any resource option, such as CVOW, as a must-run resource. The Staff believes that the result of this model run is the correct baseline to assess the incremental NPV cost of the mandates included in the GTSA as directed in the Commission's 2017 IRP Order. The incremental NPV costs associated with the GTSA are discussed further below.

STAFF'S LEAST-COST PLAN AND COST OF THE GTSA

Q8. WHAT IS THE INCREMENTAL COST OF THE GTSA COMPARED TO STAFF'S LEAST-COST PLAN DESCRIBED ABOVE?

A8. In addition to the modified Plan A described above, Staff requested that the Company re-simulate the modified Plan A where 5,000 MW of renewable resources comprised of solar resources and the CVOW project, and the 30 MW battery pilot were all included as locked-in, must-run resources. The Company's response to Staff Informal Interrogatory No. 1-1 (Attachment GLA-1) provides the results of these two model runs which are shown in the table below.

[6] Staff recognizes that this value is currently based on a limited data set in terms of number of Company owned existing solar facilities in Virginia and the number of years of available data. As such, this 20% value could change going forward as additional solar resources are added and capacity factor data for more years is obtained.

	Plan A (modified)		GTSA Sensitivity Plan A2	
	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs
2018	-	-	-	-
2019	-	-	-	-
2020	-	-	320	-
2021	-	-	411	-
2022	-	458	510	458
2023	-	458	480	458
2024	-	458	480	458
2025	-	1,591	400	1,591
2026	-	458	480	-
2027	-	458	480	-
2028	-	-	480	-
2029	-	458	480	458
2030	-	458	480	-
2031	-	-	-	458
2032	-	458	-	-
2033	-	-	-	458
Total	-	5,255	5,001	4,339
2034	-	458	-	458
2035	-	458	-	-
2036	-	458	-	458
2037	-	-	-	458
2038	-	458	-	458
2039	-	-	-	-
2040	-	-	-	-
2041	-	-	-	-
2042	-	-	-	-
2043	-	-	-	-
Total	-	7,087	5,001	6,171
NPV ($B)		$32.57		$34.42

Staff believes that Plan A (modified) is the least-cost plan. Staff's least-cost plan does not include any of the generation-related mandates contained in the GTSA even though those resources were available for the model to select. However, the model did select a natural gas-fired 3X1 CC unit in 2025. As can be seen in the table above, the incremental NPV cost for the GTSA based on these model runs is $1.85 billion. However, this does not include the GTSA mandates of $870 million spending on energy efficiency programs, the cost of the SUP, the cost of the Grid Transformation Plan, or the cost of the Transmission Pilot. The table below summarizes the total incremental NPV costs of the GTSA including those costs.

	Incremental Cost of GTSA NPV $B
5,000 MW of Solar, CVOW, and 30 MW Battery Pilot	1.85
$870 million spending on DSM	0.05
SUP	1.47
Grid Transformation Plan	2.20
Transmission Pilot	N/A
Total NPV Cost of GTSA	5.57

Staff estimates that the incremental NPV cost of the GTSA, exclusive of the Transmission Pilot, is $5.57 billion.[7] Although Staff acknowledges that the SUP, Grid Transformation Plan, and the Transmission Pilot will not affect unit dispatch in the Company's PLEXOS model runs, Staff believes it is inappropriate to ignore the associated costs for these GTSA mandates. This will be discussed further below in my discussion of the Company's rate impact analysis.

[7] This amount excludes financing costs and the associated revenue requirement ultimately collected from ratepayers will be higher.

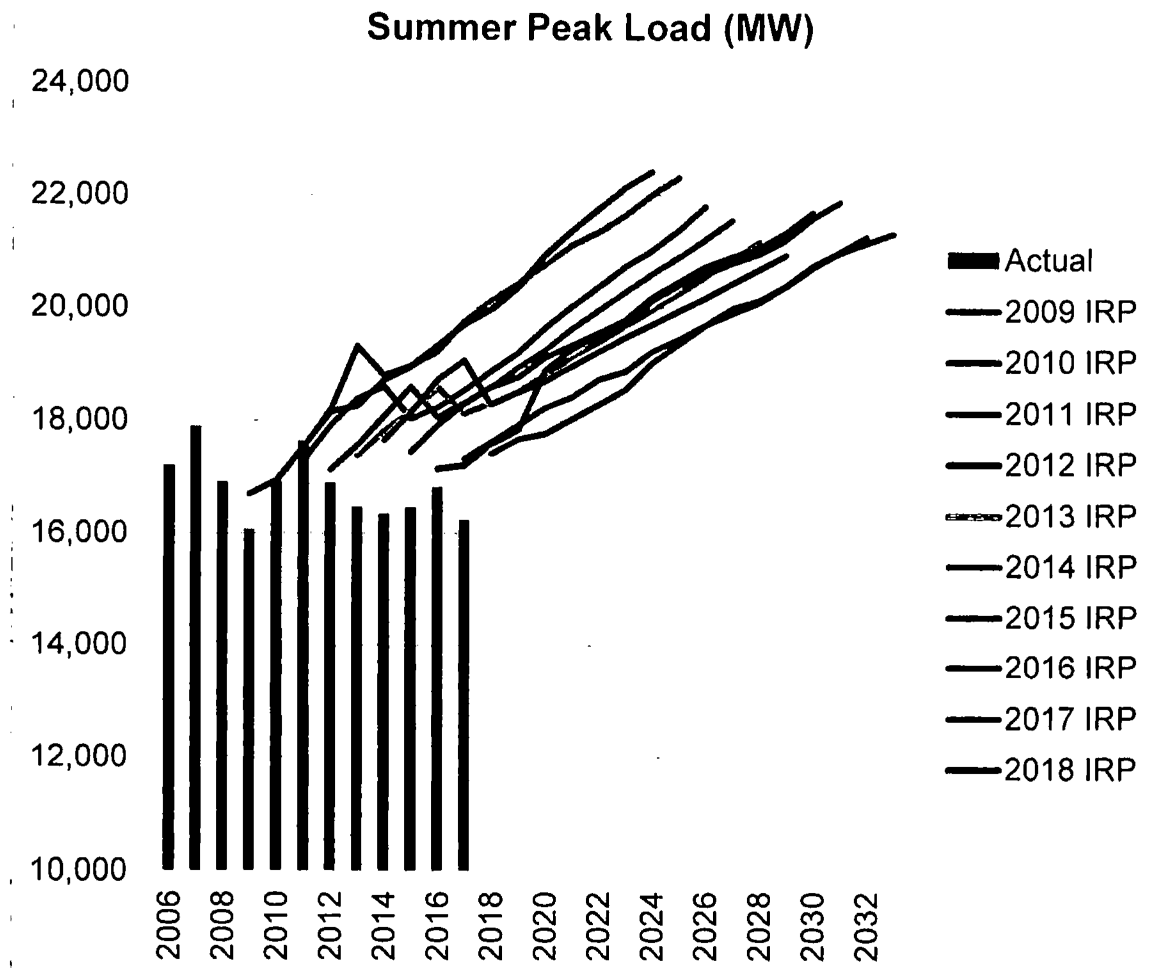
Q9. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE LEAST-COST PLAN AND THE COST OF THE MANDATES CONTAINED IN THE GTSA?

A9. Yes. The load forecast is foundational to any IRP and drives the need for additional generation resources. As discussed by Staff witnesses McBride and White, the Company's 2018 load forecast appears to be substantially inflated. In addition, this pattern of overstating future load requirements has continued for some time based on a review of the Company's past IRPs. The Company's track record in the past, combined with the Company's 2018 IRP load forecast being significantly higher than Staff witness McBride's load forecast as well as Staff witness White's alternative PJM[8]-derived load forecast, does not give Staff confidence in the model results that use the Company's inflated load forecasts as a model input.

Q10. IS THERE A CHART IN STAFF WITNESS MCBRIDE'S TESTIMONY THAT ILLUSTRATES THIS CONCERN?

A10. Yes. This concern is illustrated in Staff witness McBride's chart comparing the Company's past IRP peak load forecasts to actual peak loads that occurred in subsequent years. This chart shows the Company's noncoincident summer peak loads and is reproduced below.

[8] PJM, Interconnection, L.L.C.



As can be seen, the Company's peak load forecasts from prior IRPs have a poor track record in accurately predicting future peak loads. For example, in the 2009 IRP, the Company forecasted that the Company's noncoincident summer peak load in 2017 would be 19,703 MW. The actual 2017 noncoincident summer peak load was 16,350 MW, a difference of 3,353 MW. This is not a trivial amount. To put this in perspective, this 3,353 MW discrepancy is greater than the combined capacities of the Company's Greensville Power Station (1,585 MW) which is under construction and the Brunswick County Power Station (1,358 MW) which is the most recently completed large capacity resource to come on-line.

Q11. WHAT WAS THE ACTUAL RESERVE MARGIN FOR THE COMPANY IN RECENT YEARS?

A11. The reserve margin that is required by PJM is based on the utility's coincident peak load during the hour of the overall PJM system peak. The table below displays the actual reserve margins achieved over the last four years for the DOM LSE for both the coincident peak and the Company's noncoincident summer peak.

	Installed Capacity	Coincident Peak MW	Coincident Reserve Margin	Non-Coincident Peak MW	Non-Coincident Reserve Margin
2014	20,327	15,462	31.46%	16,348	24.34%
2015	20,203	14,650	37.90%	16,461	22.73%
2016	20,738	15,971	29.85%	16,819	23.30%
2017	19,746	15,698	25.79%	16,350	20.77%

The Company's coincident reserve margin has ranged from 25.79% to 37.9% over the last four years. This far exceeds the PJM required reserve margin of 15.9%.

Q12. HOW DOES THE COMPANY'S LOAD FORECAST COMPARE TO STAFF'S LOAD FORECASTS?

A12. The Company's 2018 IRP load forecast for the end of the planning period in 2033 is approximately 4,800 MW above Staff witness McBride's independent load forecast and some 2,800 MW higher than Staff witness White's alternative PJM-derived load forecast. If the Company had used Staff witness McBride's load forecast in the Plan A (modified) above, it is likely that the model would not have selected any resources during the 15-year planning period. If the Company had used Staff witness White's alternative PJM-derived load forecast, substantially less resources would have been needed and it is unlikely that the model would have selected a natural gas-fired 3X1 CC unit as early as 2025, or possibly not at all during the 15-year planning period.

Q13. WHAT IMPLICATIONS DOES THE LOAD FORECAST HAVE ON STAFF'S LEAST COST PLAN?

A13. The NPV cost for Staff's least-cost plan discussed above is based on the Company's load forecast rather than either of Staff's lower load forecasts. This cost may continue to be overstated to the extent the model selects additional resources (costs) due to the Company's inflated load forecast.

Q14. DO YOU HAVE ANY RECOMMENDATIONS WITH RESPECT TO THE COMPANY'S LOAD FORECAST AND MODEL RUNS FOR FUTURE IRP FILINGS?

A14. Yes. Staff recommends that all future IRP filings and certificate of public convenience and necessity ("CPCN") filings include an alternative load forecast based on the PJM-derived load forecast method described by Staff witness White in addition to the Company's preferred load forecast. In addition, Staff recommends that future IRPs and CPCN filings include an alternative set of model runs based on the alternative PJM-derived load forecast that also uses actual historic utility-specific capacity factors for solar and/or wind resources. Further, Staff recommends that future CPCN filings include a cost-benefit analysis based on the alternative PJM-derived load forecast. Additionally, such analysis should also use actual updated historic utility-specific capacity factors for solar and/or wind resources in addition to the cost-benefit method based on the Company's preferred load forecast and projected capacity factors.

Staff makes this recommendation to provide the Commission with another data point in future IRP and CPCN cases to compare and contrast with the results based on the Company's preferred method. Unlike the Company's method, an analysis based on Staff's alternative PJM-derived load forecast and that also uses actual historic utility-specific capacity factors for solar and/or wind resources is transparent and can be easily verified by Staff and respondents.

SOLAR RESOURCES

Q15. DID STAFF IDENTIFY ANY OTHER SHORTCOMINGS IN THE COMPANY'S ASSUMPTIONS REGARDING SOLAR RESOURCES?

A15. Yes. In addition to the actual observed historic utility-specific capacity factor for solar being approximately 20% rather than the 26% used by the Company, Staff identified several other concerns such as: (i) the Company's solar REC forecast: (ii) a disconnect between the Company's model runs and the representations made in the 2018 IRP; (iii) the Company's calculation of capacity revenues for solar resources; and (iv) the Company's exclusion of any third-party solar resources as a resource option available for the model to select. I will discuss each of these concerns below.

Q16. PLEASE DISCUSS STAFF'S CONCERNS WITH THE COMPANY'S SOLAR REC PRICE FORECAST.

A16. Staff witness White discusses Staff's concerns with the Company's methodology for forecasting future solar REC prices which is based on the amount of revenue required to make the investor whole after accounting for expected energy price revenues and capacity price revenues. Such a methodology virtually guarantees that solar will be economic regardless of actual market forces.

The Company's methodology for solar REC prices operates as a universal correction factor for any changes to the costs of solar or to changes to the expected revenues from the capacity and energy markets.

Q17. PLEASE DISCUSS THE DISCONNECT BETWEEN THE COMPANY'S MODEL RUNS AND REPRESENTATIONS MADE IN THE 2018 IRP.

A17. The Company's PLEXOS model runs assumed that 100% of the future solar resources would be interconnected at the transmission level. However, elsewhere in the 2018 IRP, the Company represents that 70% of solar resources will be interconnected at the transmission level and 30% will be interconnected at the distribution level. Further, the Company's rationale for its distribution-level Grid Transformation Plan[9] is partially based on the need to integrate new utility-scale renewable generation and storage as well as customer-level distributed energy resources ("DERs"). Thus, if the Company plans to interconnect 30% of the solar resources at the distribution level, then a portion of the costs for the $3 billion Grid

[9] Phase I of the Grid Transformation Plan is currently pending before the Commission in Case No. PUR-2018-00100.

Transformation Plan should be included as part of the modeled costs of utility-scale solar resources based on sound cost causation and allocation principles. The Company did not include any of these costs in the 2018 IRP model runs. Notably, the inclusion of a proper allocation of a portion of Grid Transformation Plan costs to solar resources would have made it much less likely that the model would have selected solar in any of the plans.[10]

Q18. PLEASE DISCUSS STAFF'S CONCERNS WITH THE COMPANY'S CALCULATION OF SOLAR CAPACITY REVENUES.

A18. Staff reviewed the Company's methodology for the inclusion of capacity revenues in the model runs and verified that DEV made certain assumptions to account for the probability of the solar facilities being assessed capacity penalties in the event of non-performance. As such, Staff is not opposed to the Company's methodology in this case but views it as a placeholder. The Company has limited experience with bidding solar capacity into PJM's capacity markets. As the Company gains additional experience and actual data, Staff expects the Company's methodology for calculating the expected solar capacity revenues net of non-performance penalties to be refined in future IRPs and CPCN cases.

Q19. PLEASE DISCUSS STAFF'S CONCERNS WITH THE COMPANY'S EXCLUSION OF THIRD-PARTY SOLAR RESOURCES AS AN OPTION IN DEV'S MODEL RUNS.

[10] Conversely, if the Company is, in fact, planning on interconnecting 100% of the utility-scale solar resources at the transmission level as reflected in the model runs, then it would be appropriate to not allocate any of the costs of the Grid Transformation Plan to solar resources. However, this would partially draw into question one of the needs for the Company's proposed Grid Transformation Plan.

A19. One of the requirements of the GTSA is that 25% of the solar generation capacity placed in service on or after July 1, 2018 shall be from the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities owned by persons other than a public utility. Notwithstanding the fact that the Company ignored this requirement, to the extent that purchases of solar resources from third parties are less costly than the Company's self-build option, the Company may have overstated the costs of solar in the PLEXOS model runs. Further, the Company's response to Staff Interrogatory No. 9-112 (Attachment GLA-2) indicates **[BEGIN EXTRAORDINARILY SENSITIVE – ATTACHMENT B]** [redacted] **[END EXTRAORDINARILY SENSITIVE – ATTACHMENT B]**

Q20. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S COST ESTIMATES FOR SOLAR PV?

A20. Yes. Staff has reviewed the cost data from prior IRPs compared to the 2018 IRP. This review revealed that the Company's cost estimate for solar PV continues to decrease significantly over time. For example, the overnight cost estimate for 5,000 MW of solar PV based on the 2013 IRP would have been **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In the 2018 IRP, the overnight cost estimate for 5,000 MW of solar PV has decreased to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This represents a total cost savings in the overnight costs for 5,000 MW of solar PV of $10.6 billion from a five-year delay in its development from 2013 to 2018. To the extent that the costs of solar continue to decrease, the economic case for building solar resources may become more compelling in future IRPs.

ENERGY EFFICIENCY PROGRAMS

Q21. DID THE COMPANY INCLUDE $870 MILLION OF SPENDING ON ENERGY EFFICIENCY PROGRAMS CONSISTENT WITH ENACTMENT CLAUSE 15 OF THE GTSA?

A21. As mentioned earlier, the Company did not include this in the 2018 IRP as filed. However, the Company did include $870 million of spending on energy efficiency programs in model runs in response to Staff discovery. Attachment GLA-3 contains the Company's response to Staff Interrogatory No. 1-14(i). The Company estimates the NPV cost associated with the $870 million spend on energy efficiency will add $0.05 billion in cost to the base plan based on the Company's assumptions.

Q22. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S ABILITY TO SPEND $870 MILLION ON ENERGY EFFICIENCY PROGRAMS?

A22. Yes. The GTSA only requires that DEV propose $870 million of spending on energy efficiency programs. There is no requirement that the Commission approve the proposed energy efficiency programs, which must be evaluated by the Commission under the applicable statutory standards. Further, if approved, there is still no guarantee that customers will participate at a level necessary to achieve this spending level. Finally, the GTSA exempts GS-3 and GS-4 customers which will make it more challenging for the Company to achieve the $870 million spending level contained in the GTSA. Staff Interrogatory No. 6-90 (Attachment

GLA-4) requested the Company's track record with regard to historic spending on energy efficiency programs dating back to 2009. The table below summarizes the Company's response.

	Total ($M)
Approved Cumulative Energy Efficiency Spending by the Commission 2009-2018	$368.2
Actual Cumulative Amount Spent 2009-2018	$198.6
Cumulative Amount Spent on GS-3 and GS-4 Customers 2009-2018	$22.4
Percentage of Approved Amount Actually Spent (including GS-3 and GS-4)	53.9%
Percentage of Approved Amount Actually Spent (excluding GS-3 and GS-4)	39.7%

As seen above, the Company has had difficulty in spending the prior Commission approved amounts for energy efficiency programs, likely because of lower than projected customer participation. As such, it is difficult to predict what impact the GTSA energy efficiency mandate will have on resource build plans contained in future IRPs.

<u>RGGI COMPLIANCE</u>

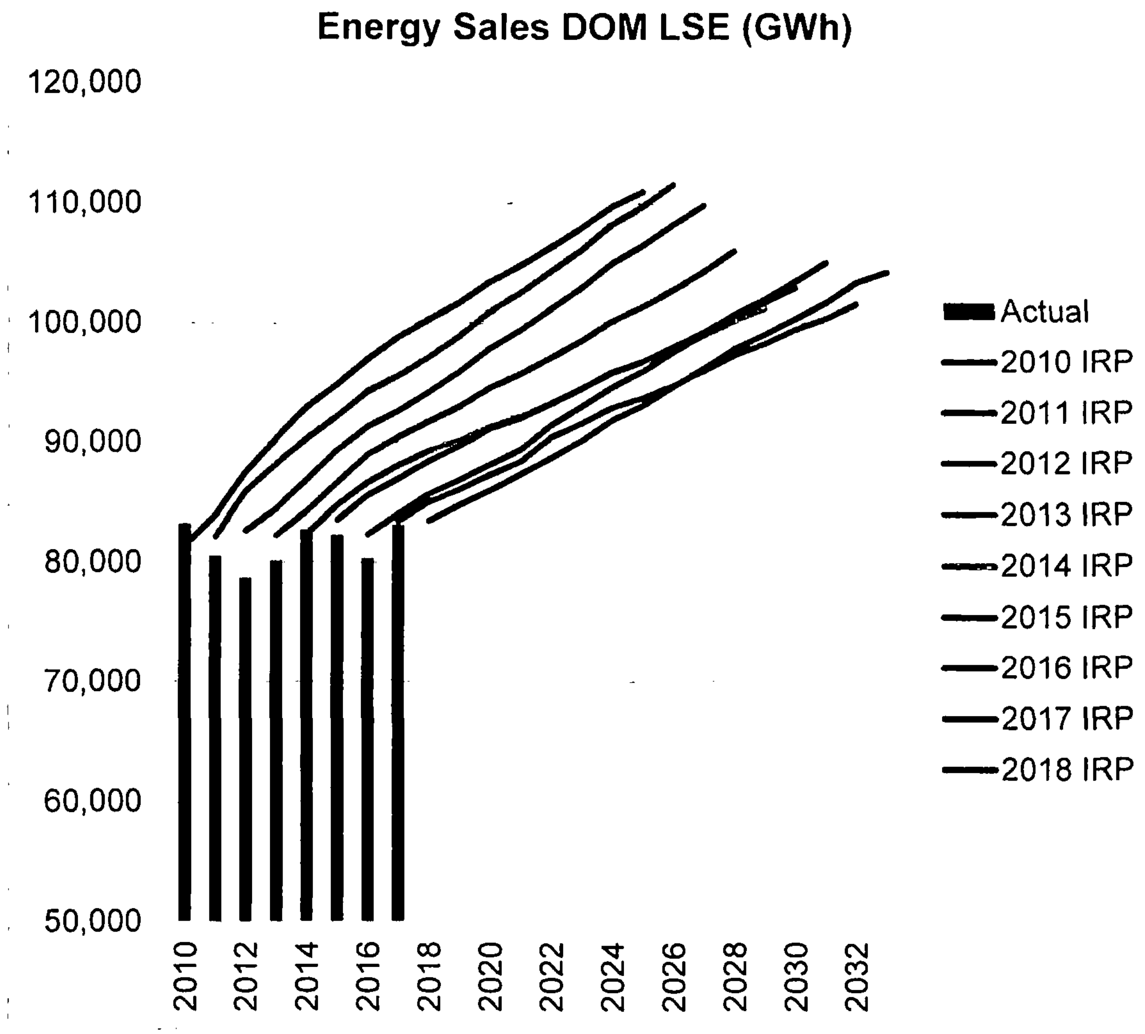
Q23. DID THE COMPANY DEVELOP ALTERNATIVE PLANS FOR POTENTIAL COMPLIANCE WITH RGGI?

A23. Yes. The Company's Plans B, C, and D reflect the results of the Company's PLEXOS model runs under different RGGI-related assumptions, including scenarios where Virginia joins RGGI as a full member or where Virginia follows

RGGI. Plan B is intended to reflect the proposed Virginia RGGI Program as developed by the Virginia Department of Environmental Quality ("DEQ") in accordance with former Governor McAuliffe's Executive Directive 11. Under this plan, the Company assumed a substantial return of allowance proceeds from the RGGI auction will flow to generators within Virginia.

Q24. DO YOU HAVE ANY GENERAL COMMENTS ON THE COMPANY'S VARIOUS RGGI PLANS?

A24. Yes. The Company's Plans B, C, and D are based on PLEXOS model runs using the same unrealistic assumptions as described earlier in my testimony. As such, Staff does not have confidence in the model results. However, with regard to compliance with RGGI, Staff identified an additional concern which casts doubt on the model results. The Company's future carbon footprint is largely dependent on expected generation to meet load, i.e., forecasted energy sales. To the extent that the Company has an inflated forecast of energy sales, the amount of fossil fuel generation needed to meet that load will also be exaggerated, and ultimately the cost of RGGI compliance will be overstated. This concern is illustrated in Staff witness McBride's chart comparing the Company's past IRP energy sales forecasts to actual energy sales that occurred in subsequent years. This chart shows the Company's annual energy sales and is reproduced below.



As can be seen, the Company's energy sales forecasts from prior IRPs have a poor track record in accurately predicting future energy sales. For example, in 2010, the Company forecasted energy sales in 2017 to be about 98,044 gigawatt-hours ("GWh"). Actual energy sales in 2017 amounted to 83,386 GWh, a difference of 14,658 GWh. The Company's forecast for 2017 was 17.6% higher than the actual 2017 energy sales.

Q25. WHAT ARE THE IMPLICATIONS OF USING STAFF WITNESS MCBRIDE'S ENERGY SALES FORECAST RATHER THAN THE COMPANY'S FORECAST?

A25. The Company's 2018 IRP energy sales forecast for the end of the planning period in 2033 is approximately 18,659 GWh, or 22% higher than Staff witness McBride's independent energy sales forecast. If the Company had used Staff witness McBride's energy sales forecast in the RGGI modeling runs, it is likely that a much different result would have been obtained and that the cost of compliance with RGGI would be lower than the Company's estimates.

Q26. DID STAFF INVESTIGATE THE IMPLICATIONS OF USING A 20% CAPACITY FACTOR FOR THE RGGI PLANS?

A26. Yes. As previously noted, the Company assumes that the solar resources have a capacity factor of 26%, but actual observed utility-specific data supports use of an approximately 20% capacity factor. Staff Interrogatory No. 9-108 requested that the Company re-run the PLEXOS model for each of the Plans A through E to reflect the actual historic utility-specific capacity factor for solar of 20%. The Company's response is shown in Staff witness White's testimony. It is important to note that these model results did not include a natural gas-fired 3X1 CC unit as an available resource for the model to select. The model did not select any solar resources for Plans A and E. However, the model did select 1,760 MW of solar resources for each of the RGGI plans using a 20% capacity factor for solar.[11]

[11] However, it should be noted that these model runs relied on the Company's inflated peak load and energy sales forecasts.

RATE IMPACT ANALYSIS

Q27. DO YOU HAVE ANY COMMENTS CONCERNING THE COMPANY'S RATE IMPACT ANALYSIS?

A27. Yes. The Company presents the incremental rate impacts of each of the Plans B through E compared to the Company's least-cost Plan A on the monthly bill for a typical residential customer. However, the Company does not present the incremental bill impacts associated with the mandates contained in the GTSA. Specifically, the Company ignored the costs of the SUP, the Grid Transformation Plan, the Transmission Pilot, the Battery Storage Pilot, and the $870 million spending requirement for energy efficiency programs. Further, since the Company included the CVOW project as a locked-in must-run resource in all the plans, there are no incremental costs reflected for the CVOW project in the rate impact analysis. Therefore, Staff finds the Company's rate impact analysis to have limited value.

A rate impact analysis that estimated the incremental rate impacts of the $5.57 billion incremental NPV costs associated with the mandates in the GTSA, as described earlier in my testimony, would be a better gauge of likely rate/bill impacts of the Company's build plans on the typical residential customer.

SHORT-TERM ACTION PLAN

Q28. WHAT IS THE PURPOSE OF THE STAP?

A28. In Staff's view, the STAP identifies and highlights areas of additional study that will be more fully developed in future proceedings in the near term. For those generation resources identified as being needed and cost-effective in the IRP during the five year STAP period, Staff would expect that applications for CPCNs for those resources would be forthcoming during that five-year period. For example, all of the alternative plans contained in the 2018 IRP call for the installation of various amounts of solar generation annually over the five-year STAP period from 2019-2023. Although these potential solar projects are purported to be least-cost resources in the 2018 IRP, the Commission has made it clear that "a finding that an IRP is reasonable and in the public interest under § 56-599 E of the Code of Virginia ("Code") in no manner represents – and should not be characterized as representing – explicit or implicit approval for construction or cost recovery of any specific resource option contained in the IRP."[12] A CPCN proceeding is typically where the Commission determines whether a specific generation resource is reasonable and prudent and in the public interest.

Q29. DO YOU HAVE ANY GENERAL COMMENTS ON THE STAP CONTAINED IN THE 2018 IRP?

A29. Yes. Given the issues identified by Staff in the 2018 IRP, Staff recommends that any CPCN application that relies on the 2018 IRP load forecast, energy sales forecast, and the 2018 IRP PLEXOS model results not be considered adequate for evaluating the CPCN. As I discussed earlier in my testimony, Staff recommends that future CPCN filings also include a cost-benefit analysis based on the alternative PJM-derived coincident load forecast described by Staff witness White in his testimony. In addition, Staff recommends the cost-benefit analysis also use actual updated historic utility-specific capacity factors for solar and/or wind resources.

[12] *Commonwealth of Virginia, ex. rel., State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code §56-597 et seq.,* Case No. PUE-2011-00092, Doc. Con. Cen. No. 120320147, Order on Certified Question at 4 (Mar. 19, 2012).

Staff recommends that this alternative cost-benefit analysis be included in subsequent CPCN filings in addition to the Company's cost-benefit method based on the Company's preferred load forecast, preferred energy sales forecast, and projected capacity factors.

Staff makes this recommendation to provide the Commission with another data point in subsequent CPCN cases to consider along with the results based on the Company's preferred method. In addition, unlike the Company's methodology, an analysis based on Staff's alternative PJM-derived load forecast and that also uses actual historic utility-specific capacity factors for solar and/or wind resources is transparent and can be easily verified by Staff and respondents.

Q30. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE COMPANY'S STAP?

A30. Yes. The STAP is the first step in implementing the Company's anticipated build plan for the 15-year planning period as described in the 2018 IRP. As such, Staff offers the following summary of the Company's build plan based on the Company's Plan E with one addition I will discuss further below.

Resource	Capacity
Solar	6,000 MW (nameplate)
CVOW	11 MW (nameplate)
Gas CT's	3,664 MW
Nuclear License Extensions	3,349 MW
Offshore Wind	2,000 MW (nameplate)
TOTAL	15,024 MW

The Company has plans to build 15,024 MW of capacity resources over the 15-year planning period. This compares to the Company's noncoincident peak of 16,350 MW and the coincident peak of 15,698 MW experienced in 2017. In other words, the Company's build plan is nearly equal to its existing coincident peak load. This is an aggressive build plan especially considering that the Company's 2018 IRP load forecast for the end of the planning period in 2033 is approximately 4,800 MW above Staff witness McBride's independent load forecast and some 2,800 MW higher than Staff witness White's alternative PJM-derived load forecast.

Q31. WHY DID THE STAFF INCLUDE 2,000 MW OF OFFSHORE WIND IN THE TABLE ABOVE?

A31. Although 2,000 MW of offshore wind is not included in Plan E, Staff notes that subsequent to filing the 2018 IRP, the Company filed an application for a prudency review for the CVOW demonstration project.[13] In that case, the Company indicated that it will pursue a much larger roll-out of utility-scale offshore wind, beginning in 2024, if the demonstration project shows it to be economic.[14] Therefore, I have included the 2,000 MW of offshore wind in the table above.

Q32. DO YOU HAVE ANY COMMENTS CONCERNING THE NUCLEAR LICENSE EXTENSIONS INCLUDED IN THE STAP?

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[13] Case No. PUR-2018-00121.

[14] It is not clear to Staff whether the Company would construct 2,000 MW of offshore wind in addition to or in lieu of the resources identified in Plan E, if found to be economic. For example, if the Company determines that 2,000 MW of offshore wind is economic, perhaps the Company does not need to pursue the nuclear license extensions for Surry Units 1 and 2.

A32. Yes. As discussed by Staff witness Myers in her testimony, the lifetime revenue requirement of the projected **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of capital costs associated with the nuclear license extensions of North Anna Units 1 and 2 and Surry Units 1 and 2 that the Company is pursuing from the Nuclear Regulatory Commission is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to be recovered over the extended service lives of the units.

The nuclear license extensions are projects that require a significant amount of lead time and the Company is currently incurring expenses in pursuing them. As further discussed by Staff witness Myers, the Company stated that it plans to file for approval of a rate adjustment clause pursuant to § 56-585.1 A 6 of the Code sometime after January 1, 2020.

Staff has concerns that, given the Company's aggressive build plan, and given the Company's inflated load forecast, that the nuclear license extensions may not be needed by the time the projects come on-line. However, the Company is currently incurring costs and will begin to seek cost recovery from customers as early as 2020.

Q33. DO YOU HAVE ANY COMMENTS CONCERNING THE COMPANY'S PLANS FOR SOLAR GENERATION IN THE STAP?

A33. Yes. In the 2017 IRP, the Company stated that it was only capable of installing 240 MW of solar annually and included this level in the PLEXOS model as a modeling constraint. In the 2018 IRP, the Company has doubled this annual limit to 480 MW and is committed to installing a large amount of solar in the STAP and continuing throughout the 15-year planning period.

Q34. DOES STAFF AGREE WITH THE COMPANY'S IMPLEMENTATION PLANS FOR SOLAR?

A34. Staff believes that a more cautious implementation of solar especially during the STAP may be more prudent for several reasons.

First, a prudency review of the proposed CVOW demonstration project is currently pending before the Commission and the Company has indicated that it may pursue a much larger development of offshore wind (2,000 MW) if it proves to be economic. If the demonstration project proves that utility-scale offshore wind is economic compared to solar, then it may make sense to get the results of the CVOW demonstration project before deploying a large amount of solar.

Second, Staff has identified several concerns with solar inputs used in the model including the capacity factor that the Company uses to evaluate solar. Staff believes it may be prudent to take a slower more cautious approach to allow time for the Company to gather more data and more experience with solar resources prior to a larger rollout.

Third, as mentioned earlier in my testimony, based on the Company's 2013 IRP data and 2018 IRP data, the costs of solar have decreased substantially from 2013 to 2018. By delaying deployment of 5,000 MW of solar from 2013 to 2018, a total estimated cost savings of $10.6 billion is realized from just a five-year delay. The percentage cost decrease exceeded the value of any investment tax credit that would have been realized. Thus, based on history, it may make sense to take a more cautious approach in order to take advantage of the continuing fall in the costs of solar.

Fourth, the Company's plans include exclusively self-build solar. Staff believes that third-party market purchases of solar may provide a lower cost option and the Company has not adequately explored this option. In fact, the GTSA requires that 25% of the solar placed into service after July 1, 2018, to be purchased by the Company from solar facilities owned by persons other than a public utility.

Q35. DO YOU HAVE ANY RECOMMENDATIONS FOR THIRD-PARTY SOLAR OPTIONS?

A35. Yes. As I discussed earlier in my testimony, the Company assumed in the PLEXOS model runs that 100% of solar would be interconnected at the transmission level, and included none of the costs of the Company's Grid Transformation Plan as part of the solar costs modeled by PLEXOS. Notwithstanding, one of the main reasons given by the Company to justify the $3 billion Grid Transformation Plan is the need to integrate, on the distribution level, new utility-scale renewable generation and storage, as well as customer-level DERs.

Given that the Company is developing a Grid Transformation Plan that is designed specifically to integrate customer-level DERs, and given the Company's peak load forecast, Staff believes the Company should explore developing a rebate program to incent customer-owned rooftop solar systems. Staff believes that it is logical to incent these DERs particularly since the Company's Grid Transformation Plan pursuant to the GTSA is designed specifically to handle these DERs. Staff also notes that such a program could be considered to be a peak shaving program and eligible for cost recovery through Rider C1A. To the extent that the program passed the economic tests, it may obviate the need for some of the more expensive capacity resources as described in the Company's proposed build plan. Such a program would be more environmentally benign as it would take advantage of existing brownfield sites rather than the greenfield sites required for utility-scale solar.

Q36. DO YOU HAVE ANY FINAL RECOMMENDATIONS?

A36. Yes. Staff recommends that the Commission direct the Company to file an annual report on solar resources that contains the following for each solar facility located in Virginia: (1) name of the facility; (2) nameplate capacity; (3) monthly and annual capacity factor realized; (4) hourly energy production for each of the 8,760 hours in the year; (5) hourly PJM energy price for each of the 8,760 hours in the year; (6) a calculation of the market value of the energy produced [(4) X (5)]; (7) whether or not it was bid into the PJM capacity market and capacity revenues received; (8) PJM capacity penalties assessed; (9) number of solar RECs created; (10) revenues received through the sale of solar RECs; and (11) average price received for solar RECs.

Q37. DOES THIS CONCLUDE YOUR TESTIMONY?

A37. Yes, it does.

ATTACHMENT GLA-1

183040273

Virginia Electric and Power Company
Case No. PUR-2018-00065
Virginia State Corporation Commission Staff
Informal Set 1

The following response to Question No. 1 of the Informal First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on August 1, 2018 has been prepared under my supervision.

Jennifer Valaika for
Ted Fasca
Manager – Generation System Planning
Dominion Energy Virginia

The following response to Question No. 1 of the Informal First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on August 1, 2018 has been prepared under my supervision.

Jennifer Valaika for
Vishwa B. Link
McGuireWoods

Question No. 1

Please provide results for the following PLEXOS model scenarios for Plan A:

a. **Plan A Modified**
Re-simulate Plan A with the following assumptions:
   1. Future generating resources:
      i. All resources are offered economically only (no "must take")
      ii. Add 3x1 CC with oil backup as an available resource option
      iii. Add 30 MW battery storage as an available resource option
      iv. Modify solar resource capacity factor from 26% to 20%
      v. Nuclear life extensions available economically
   2. Existing generation resources (no change)
      i. Maintain cold storage/retirements and associated timeline
   3. DSM resources (no change)
   4. Load/commodity forecasts (no change)

b. **Plan A1**
Re-simulate the above scenario (**Plan A Modified**) to reflect Grid Transformation &

Security Act ("GTSA") with at least 3,000 MWs nameplate "must take" renewable resources and include "must take" 30 MW battery storage.

c. <u>Plan A2</u>
Re-simulate the above scenario (**Plan A Modified**) to reflect Grid Transformation & Security Act ("GTSA") with at least 5,000 MWs nameplate "must take" renewable resources and include "must take" 30 MW battery storage.

Response:

The Company objects to this request on the basis that it would require original work. Notwithstanding and subject to this objection, the Company provides the following response:

See Attachment Informal Staff Set 1-1 (TF).

Staff Informal Set 1-1

	Plan A (modified)		GTSA Sensitivity Plan A1		GTSA Sensitivity Plan A2	
	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs
2018	-	-	-	-	-	-
2019	-	-	-	-	-	-
2020	-	-	320	-	320	-
2021	-	-	411	-	411	-
2022	-	458	510	458	510	458
2023	-	458	480	458	480	458
2024	-	458	480	458	480	458
2025	-	1,591	400	1,591	400	1,591
2026	-	458	480	-	480	-
2027	-	458	-	-	480	-
2028	-	-	-	458	480	-
2029	-	458	-	-	480	458
2030	-	458	-	458	480	-
2031	-	-	-	458	-	458
2032	-	458	-	-	-	-
2033	-	-	-	458	-	458
Total	-	5,255	3,081	4,797	5,001	4,339
2034	-	458	-	-	-	458
2035	-	458	-	458	-	-
2036	-	458	-	458	-	458
2037	-	-	-	458	-	458
2038	-	458	-	458	-	458
2039	-	-	-	-	-	-
2040	-	-	-	-	-	-
2041	-	-	-	-	-	-
2042	-	-	-	-	-	-
2043	-	-	-	-	-	-
Total	-	7,087	3,081	6,629	5,001	6,171
NPV ($B)		$ 32.57		$ 33.96		$ 34.42

<u>Modifications to Plan A</u>

1) Adjusted tracker solar capacity factor to approximately 20%
2) Added 3x1 CC and 30 MW Battery as available new build option
3) Removed US-3 Solar units
4) CVOW is available in 2021 as a new build option

<u>Notes:</u>

1) NPV includes solar integration cost
2) 458 MWs represents 2 large CTs
3) 1591 MWs represents 3x1 CC
4) Plans A1 and A2 include forced in 11.126 MW CVOW in 2021 and 30 MW battery in 2022
5) Plan A1 includes forced in 3040 MW of solar
6) Plan A2 includes forced in 4960 MW of solar

ATTACHMENT GLA-2

EXTRAORDINARILY SENSITIVE – ATTACHMENT B

ATTACHMENT GLA-3

18082973

Virginia Electric and Power Company
Case No. PUR-2018-00065
Virginia State Corporation Commission Staff
First Set

The following **revised** response to Question No. 14(i) (dated June 8, 2018) of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on May 3, 2018 has been prepared under my supervision as it pertains to demand-side management programs.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

The following **revised** response to Question No. 14(i) (dated June 8, 2018) of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on May 3, 2018 has been prepared under my supervision as it pertains to integrated resource planning.

Ashwani Vaswani
Manager, Energy Market Quantitative Analysis and Integrated Resource Planning
Dominion Energy Services, Inc.

The following **revised** response to Question No. 14(i) (dated June 8, 2018) of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on May 3, 2018 has been prepared under my supervision as it pertains to legal matters.

Vishwa B. Link
McGuireWoods LLP

Question No. 14

Please reference enactment clause 15 of Senate Bill 966 (Grid Modernization and Security Act of 2018) which requires a Phase II Utility to develop a program of energy conservation measures with a projected cost of $870 million for the period beginning July 1, 2018 and ending July 1, 2028. Please answer the following:

i. If the Company has not yet developed a proposed program of energy conservation measures totaling $870 million contained in the law, please provide answers (d), (e) and (h) using estimated MW and MWh values for generic DSM programs assuming an expenditure of $870 million over the 2018 — 2028 time period.

Response:

The Company objects to this request on the basis that it would require original work. Notwithstanding and subject to this objection, the Company provides the following response:

Based on follow up discussion with Staff, the Company provides this revised response, emphasizing the following caveats and assumptions. This PLEXOS run does not include "generic DSM." Consistent with supply side resource technologies and attributes, there is no "generic DSM" because differing technologies, target participants, timing of reductions, and rate structures provide differing cost and benefit streams for Energy Efficiency ("EE") programs. The EE that the Company will propose in filings after the 2018 DSM filing will be the result of a stakeholder process which has yet to be developed or implemented.

Instead, the Company simulated potential reductions at historical costs by developing an average cost per historical MWh achieved. This was the result of summing all dollars spent on Company-sponsored EE programs historically (from 2009-2017) and dividing by all MWh reflected in the Company's EM&V reports from 2010 thru 2017. For simplicity, no discount or escalation factors were applied to either of these values.

The sum of dollars actually spent was increased by a factor to reach the $870 million in the GTSA.[1] The same factor was used to develop potential energy reductions based upon this average spend for prior EE savings. This resulted in a total of 2,620,216 MWh. Another simplifying assumption made to conduct this analysis is the energy reductions were assumed to occur based upon the system load shape and do not reflect actual load shapes for any known program or measures.

The cycle for DSM program approvals means that the first filing that could potentially reflect proposed programs fully developed through the newly created stakeholder process outlined in the GTSA would be the fall of 2019, with a Commission Order potentially approving the request in the spring of 2020. Based on this assumed timeline and not reflecting any filing for DSM programs that could be made in the 2018 filing, reductions were included within PLEXOS beginning in 2020 with growing contributions thru 2028, consistent with dates listed in the GTSA. Annual energy reductions of 6% of the total energy amount achieved are assumed

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[1] While the Company used $870 million because of the call of the question, the $870 million in Enactment Clause 15 of the GTSA ("Enactment Clause 15") includes "a margin to be recovered on operating expenses" and "any existing approved energy efficiency programs." In addition, Enactment Clause 15 requires the Company to "develop a proposed program of energy conservation measures...for the submission of a petition or petitions for approval to design, implement, and operate energy efficiency programs...." The Commission would still need to approve pursuant to Va. Code § 56-585.1 A 5 c, the Company's proposed program of energy conservation measures developed pursuant to Enactment Clause 15.

beginning in 2030 and continuing through 2043 to reflect the expiration of measure produced savings.

Of note, while the Company anticipates potentially filing for program approval in the fall of 2018 and will review its proposed programs through its own stakeholder process, those potential programs have not been evaluated to date and are not reflected within this model run.[2] It is also critical to note that programs that were historically offered to GS3 and GS4 customers may no longer be offered due to statutory amendments included in the GTSA. The reductions included in this run are illustrative only based upon a number of simplifying assumptions, and there has been no analysis conducted by the Company to confirm that:

1. There is any set of programs that would produce these same results;
2. Future EE program costs would be consistent with historical costs;
3. Future programs would be found cost-effective;
4. Future programs would be found in the public interest and approved by the Commission;
5. Customers would choose to participate in the future programs to achieve the calculated savings.

Subject to these caveats and simplifying assumptions, see Attachment Staff Set 1-14 (i) (AV) for the build plan and NPV for Plan E: Federal CO_2 Program with the Modified Load. See Confidential Attachment Staff Set 1-14(i) (DRK) for the assumptions included to calculate the modified load within the PLEXOS model run. Confidential Attachment Staff Set 1-14(i) (DRK) is confidential in its entirety, and is being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information entered on May 18, 2018, the Company's Second Motion for Additional Protective Treatment for Extraordinarily Sensitive Information dated June 1, 2018, any subsequent protective order or protective ruling issued in this proceeding, and the Agreements to Adhere executed pursuant to any such orders or rulings.

[2] It is the Company's position that these programs would still "count" towards the $870 million spending goal for proposed programs set forth in Enactment Clause 15.

180840273

<u>**Virginia Electric and Power Company**</u>
<u>**Case No. PUR-2018-00065**</u>
<u>**Virginia State Corporation Commission Staff**</u>
<u>**First Set**</u>

The following **supplemental** response to Question No. 14(i) (dated June 15, 2018) of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on May 3, 2018 has been prepared under my supervision as it pertains to demand-side management programs.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

The following **supplemental** response to Question No. 14(i) (dated June 15, 2018) of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on May 3, 2018 has been prepared under my supervision as it pertains to integrated resource planning.

Ashwani Vaswani
Manager, Energy Market Quantitative Analysis
and Integrated Resource Planning
Dominion Energy Services, Inc.

The following **supplemental** response to Question No. 14(i) (dated June 15, 2018) of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on May 3, 2018 has been prepared under my supervision as it pertains to legal matters.

Vishwa B. Link
McGuireWoods LLP

Question No. 14

Please reference enactment clause 15 of Senate Bill 966 (Grid Modernization and Security Act of 2018) which requires a Phase II Utility to develop a program of energy conservation measures with a projected cost of $870 million for the period beginning July 1, 2018 and ending July 1, 2028. Please answer the following:

i. If the Company has not yet developed a proposed program of energy conservation measures totaling $870 million contained in the law, please provide answers (d), (e) and (h) using estimated MW and MWh values for generic DSM programs assuming an expenditure of $870 million over the 2018 — 2028 time period.

Response:

The Company objects to this request on the basis that it would require original work. Notwithstanding and subject to this objection, the Company provides the following response:

See Attachment Staff Set 1-14(i) (AV) (Supp 6-15-18), which provides the results of the requested modified load run against Plan A. All of the caveats and assumptions discussed in the Company's revised response to Staff Set 1-14(i), which was provided on June 8, 2018, are also applicable to this response.

Year	Plan A: No CO_2 Tax	Plan E: Federal CO_2 Program	Plan E with Modified Load: Federal CO_2 Program
Approved DSM: 304 MW, 805 GWh by 2033			
2019	Greensville SLR NUG(1)	Greensville SLR NUG(1)	Greensville SLR NUG(1),
2020	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)
2021	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4), PP5
2022	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3
2023	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)
2024	CT SLR (480 MW)	CT SLR (400 MW)	CT SLR (400 MW)
2025	CT SLR (400 MW)	CT SLR (480 MW)	CT SLR (480 MW)
2026	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)
2027	CT SLR (480 MW)	SLR (480 MW)	CT SLR (480 MW)
2028	SLR (480 MW)	SLR (480 MW)	SLR (480 MW)
2029		CT SLR (400 MW)	SLR (480 MW)
2030	CT	CT SLR (320 MW)	CT SLR (480 MW)
2031	CT SLR (160 MW)	CT SLR (80 MW)	CT
2032	CT SLR (240 MW)	SLR (480 MW)	SLR (480 MW)
2033	SLR (80 MW)	SLR (480 MW)	SLR (480 MW)
2034	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)
2035	CT	CT SLR (400 MW)	CT SLR (320 MW)
2036	CT	CT SLR (320 MW)	CT
2037			SLR (240 MW)
2038	CT	CT	CT
2039			
2040			
2041			
2042			
2043			

Total Plan NPV ($B)	$33.34	$36.42	$36.47
Plan Summaries	CC: - MW CT: 5,954 MW Aero: - MW Solar: 4,960 MW	CC: - MW CT: 5,496 MW Aero: - MW Solar: 6,960 MW	CC: - MW CT: 5,496 MW Aero: - MW Solar: 6,960 MW

Key: Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); CT AERO: Aero-derivative CT (119 MW); CVOW: Coastal Virginia Offshore Wind Technology Advancement Project; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SLR: Generic Solar; SLR NUG: Solar NUGs; YT: York Town Power Station;

(1) Solar NUGs include 660 MW of NC Solar NUGs and 100 MW of VA Solar NUGs that come online I
(2) These units entered into cold storage in April 2018.
(3) Pittsylvania is planned to enter cold storage in August 2018.
(4) These units are planned to enter into cold storage in December 2018.

ATTACHMENT GLA-4

Virginia Electric and Power Company
Case No. PUR-2018-00065
Virginia State Corporation Commission Staff
Sixth Set

The following response to Question No. 90 of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on June 7, 2018 has been prepared under my supervision as it pertains to EC programs generally.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

The following response to Question No. 90 of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on June 7, 2018 has been prepared under my supervision as it pertains to EC program compliance.

Jarvis E. Bates
Energy Conservation Compliance Consultant
Virginia Electric and Power Company

Question No. 90

What is the cumulative total dollar amount that the Commission has approved for Company DSM programs from 2009 through 2018? Of this amount, how much did the Company actually spend on Commission-approved DSM programs? Of the amount actually spent on Commission-approved DSM programs, how much of this spend went to programs for GS-3 and GS-4 customers?

Response:

See the table below for the requested information.

	Total ($Mil)
Cumulative Approved Total [1]	$368.2
Cumulative Spend Total [2]	$198.6
Cumulative GS-3 and GS-4 Spend Total [3]	$22.4

Notes:

1. Based on Commission approved cost caps through 2017 VA DSM Case (PUR-2017-00129) which includes approval timeframe out to 2022.
2. Includes preliminary 2017 results still subject to true up in upcoming 2018 VA DSM Case.
3. Includes incentive costs only.
4. All costs represent spend for Energy Efficiency Programs.