COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PREFILED STAFF TESTIMONY

VIRGINIA ELECTRIC AND POWER COMPANY

To revise its fuel factor pursuant to
§ 56-249.6 of the Code of Virginia

Testimony of:

Earnest J. White
Division of Public Utility Regulation

Public Version

PUR-2021-00097

June 15, 2021

Summary of Testimony – Earnest White

My testimony contains the following findings and recommendations:

- The models and methodologies employed by Virginia Electric and Power Company ("DEV" or "Company") to prepare its short-term forecasts are reasonable and are consistent with those used in recent fuel factor proceedings. DEV's load forecast for the current period is less than last year's projection. The Company developed its forecast in February 2021 using base data from Moody's Economy.com as of October 2020.
- The recovery from the global pandemic is on-going and as such short-term forecasts may be impacted as economic and statistical models adapt to new trends. However, the Company's forecasts appear reasonable given the current forecasting challenges.
- DEV's fuel factor application requests to increase its fuel factor by 0.3427 ¢ per kilowatt-hour ("¢/kWh") from 1.7021 ¢/kWh to 2.0448 ¢/kWh effective July 1, 2021.
- If approved the proposed fuel factor would increase the typical monthly bill of a residential customer using 1,000 kWh by approximately $3.43.
- DEV forecasts an under-recovery position of approximately $127.97 million as of May 31, 2021.
- The Company's application includes historical and forecasted data for its cost of generation, purchases, and off-system sales. As part of this data, the Company has provided historical and projected data for individual unit performance.
- The data provided by the Company as part of its forecast for future unit operation is reasonable and compares favorably with historical performance.
- Based on its overall review, Staff finds that the Company's projected fuel expenses and the underlying assumptions are reasonable for purposes of this fuel factor proceeding.
- The fuel factor proposed by the Company appears reasonable.

PRE-FILED TESTIONY
OF
EARNEST J. WHITE

VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUR-2021-00097

PUBLIC VERSION

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

A1. My name is Earnest J. White. I am a Principal Utilities Policy Specialist in the Commission's Division of Public Utility Regulation.

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

A2. On May 13, 2021, Virginia Electric and Power Company ("Dominion Energy Virginia", "DEV", or the "Company") filed an application, testimony, and exhibits in support of its request to increase its current fuel factor from 1.7021cents per kilowatt-hour ("¢/kWh") to 2.0448 ¢/kWh, representing an increase of 0.3427 ¢/kWh, effective on or after July 1, 2021, pursuant to § 56-249.6 of the Code of Virginia. By Order dated May 26, 2021, the Commission established the instant case, set a date for a public hearing on the Company's application, established a schedule for the filing of pleadings and testimonies by interested parties, and directed the Commission Staff ("Staff") to investigate the application.

This revised fuel factor is calculated to recover the Company's projected Virginia jurisdictional fuel expenses of approximately $1.39 billion for the period July 1, 2021 through June 30, 2022 ("Forecast Period") and the approximately $71.6 million projected under-recovery Virginia jurisdictional fuel expense balance at June 30, 2021. The Company stated the primary reason for the increase in the forecasted system fuel expense as compared to the 2020-2021 fuel year is the change in commodity prices, particularly for natural gas and purchased power.[1]

My testimony is arranged in two parts. The first part of my testimony evaluates the reasonableness of the Company's forecasted fuel costs for the twelve-month period commencing July 1, 2021. Specifically, I evaluate the reasonableness of the Company's forecasted energy sales, forecasted fuel prices, projected market energy prices, and estimated emissions allowance prices used in the determination of the Company's proposed fuel factor. The second part of my testimony presents the Staff's conclusions and recommendations relative to the reasonableness of the Company's: (i) proposed fuel factor; (ii) projected deferral balance as of June 30, 2021; (iii) generating unit performance; and (iv) power supply assumptions underlying the Company's projected Virginia jurisdictional fuel expense.

Q3. PLEASE EXPLAIN THE PRESENT FUEL FACTOR.

A3. The fuel factor is the average fuel expense per kWh the Company ultimately recovers from consumers. The present fuel factor consists of a current period factor for DEV's current projection of fuel expenses and a correction factor addressing any over- or under-recovery for prior period expenses. Projected Virginia jurisdictional fuel expenses (current period factor) are directly determined not only by estimates of electricity demand and fuel prices, but also by estimates of generating unit performance, power purchases, off-system power sales, and other system parameters, as discussed further in my testimony.

Q4. PLEASE SUMMARIZE THE COMPANY'S PROPOSED FUEL FACTOR.

[1] Prefiled Direct Testimony of Company witness James L. Neal ("Neal Direct") at 3 and Prefiled Direct Testimony of Amanda K. Prestage ("Prestage Direct") at 6.

A4. The Company's total fuel factor of 2.0448 ¢/kWh is proposed to go into effect on July 1, 2021. The proposed fuel factor will increase the average weighted monthly bill (four summer months and eight base months) for a residential customer using 1,000 kWh by $3.43 from $117.85 to $121.29 (or by 2.9 percent).[2]

The total proposed fuel factor of 2.0448 ¢/kWh is comprised of a current period factor of 1.9443 ¢/kWh and a prior period (or correction) factor charge of 0.1005 ¢/kWh. The proposed current period factor, designed to recover estimated fuel expenses for the 12-month period July 1, 2021, through June 30, 2022, is based on projected Virginia jurisdictional fuel expenses of approximately $1.39 billion and energy sales of approximately 71.2 million megawatt-hours ("MWh"). The proposed current period factor of 1.9443 ¢/kWh represents an increase of 0.0874 ¢/kWh, or 4.7 percent from the current period factor of 1.8569 ¢/kWh in effect.

The proposed prior period factor charge of 0.1005 ¢/kWh is designed to recover approximately $71.6 million, which is DEV's projected under-recovery fuel balance as of June 30, 2021.[3] The Company's projection of $71.6 million is based on the actual under-recovery balance of $76.9 million as of June 30, 2021 for the July 1, 2020 through June 30, 2021 current period expense, and a projected net fuel expense over-recovery of $5.3 million for the remaining June 30, 2020 prior period expense.[4] The proposed prior period factor of 0.1005 ¢/kWh represents an increase of 0.2553 ¢/kWh compared to the credit of 0.1548 ¢/kWh currently in effect.

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[2] Prefiled Direct Testimony of Company witness Timothy A. Stuller ("Stuller Direct") at 5.
[3] Stuller Direct at 2.
[4] *Id.*

Energy Sales and Commodity Forecasts

Q5. HOW DOES THE COMPANY FORECAST ENERGY SALES?

A5. The Company uses several single equation econometric models to forecast energy sales by customer class in the its service territory. Customer classes include residential, commercial, industrial, public authority, and sales for resale. Explanatory variables include such items as stocks of electric heating and cooling appliances and usage rates, unemployment rates, moving averages of real seasonal electricity prices, state housing permits, disposable income, commercial and industrial employment, weather and dummy variables. The Company did detail recent new developments to its forecasting models and methodologies in its response to Staff Interrogatory No. 4-30[5] The Company obtained the economic variables for the Commonwealth required to drive the forecasting models from Moody's Analytics Economy.com ("Moody's"), of West Chester, Pennsylvania. The Company used economic data from Moody's October 2020 vintage.[6]

Applying statistical methods to the weather and economic data, the models produce the Company's energy sales forecast. Generally, once the energy sales forecast is developed, DEV adjusts the forecast for estimated reductions resulting from implementation of the Company's demand-side management ("DSM") and energy efficiency ("EE") programs.[7] According to DEV's response to Staff Interrogatory No. 3-17, the Company assumed MWh savings from pending and approved DSM and EE programs, in addition, the Company made assumptions about MWh savings from generic DSM and EE programs. These assumptions, through the year 2040, are reproduced below.[8]

[5] *See* Company response to Staff Interrogatory No. 4-30 Attachment EJW-1.
[6] *See* Company response to Staff Interrogatory No. 3-14, Attachment EJW-2.
[7] Prestage Direct at 5.
[8] *See* Company response to Staff Interrogatory No. 3-17, Attachment EJW-3.

Year	Pending & Approved DSM & EE Programs	Generic DSM & EE Programs
2020	-	1,120,117
2021	190,920	1,146,187
2022	544,938	1,346,574
2023	899,006	1,649,541
2024	1,266,768	1,906,441
2025	1,607,767	1,851,617
2026	1,962,001	1,862,345
2027	2,316,233	1,860,304
2028	2,509,660	1,942,376
2029	2,479,532	1,906,665
2030	2,479,532	1,952,064
2031	2,479,532	1,994,345
2032	2,511,743	2,095,547
2033	2,413,919	2,075,998
2034	2,293,536	2,118,910
2035	2,173,774	2,172,982
2036	2,081,032	2,287,645
2037	1,932,886	2,291,326
2038	1,812,447	2,337,806
2039	1,691,526	2,365,795
2040	145,853	207,041
Total	35,792,606	38,492,024

Table 1: Company's DSM and EE assumptions through 2040

The models and methodologies employed by the Company to prepare its energy sales forecasts for this fuel factor were finalized in February 2021 (*see* DEV's response to Staff Interrogatory No 3-15, Attachment EJW-4) and are consistent with those used in prior fuel factor proceedings. The Company's methodology to develop its short-term load forecast and to project its jurisdictional sales at a customer class level is an essential part of determining the fuel factor rate to be charged to customers. The use of deferred accounting with an annual true up, however, minimizes the risk of deviation in the Company's short-term load forecast from actual customer load.

Q6. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE COMPANY'S ENERGY SALES FORECAST?

A6. As of February 2021, the Company projected its total Virginia jurisdictional energy sales to be approximately seven percent higher than its prior July 2020 to June 2021 forecast as shown below.

Month	2020-2021 Forecast (GWh)	2021-2022 Forecast (GWh)	Change (%)
July	6,382.4	6,582.5	3.1%
August	6,237.7	6,975.2	11.8%
September	5,223.5	6,109.4	17.0%
October	4,741.1	5,200.9	9.7%
November	5,125.9	5,247.0	2.4%
December	6,028.6	5,986.4	-0.7%
January	6,463.4	6,459.2	-0.1%
February	5,716.8	6,455.9	12.9%
March	5,340.4	5,915.8	10.8%
April	4,529.8	5,458.3	20.5%
May	5,036.3	4,989.2	-0.9%
June	5,743.2	5,862.7	2.1%
Total	66,569.1	71,242.6	7.0%

Table 2. Comparison of Energy Sales Forecasts in Case Nos. PUR-2020-00031 and PUR-2021-00097[9]

This forecasted increase in jurisdictional energy sales is significant compared to the last fuel factor. Staff notes, however, that stay-home orders and other measures taken during the global pandemic are being lifted. As such, it is reasonable to assume that there will be some increase in energy demand, and therefore energy sales, as economic activity recovers and perhaps grows. That said, the Company's forecast of energy sales in this proceeding is seven percent higher than the energy sales forecast in the previous fuel proceeding. The energy sales forecast in the previous proceeding *did not* account for the pandemic, as such any demand suppression from the pandemic would not have dampened the Company's load forecast.[10] Further, the Company's energy sales

[9] GWh stands for Gigawatt-hour. *See* DEV Witness Farmer's Schedule 1, Case No. PUR-2020-00031 and DEV Witness Prestage's Schedule 1, Case No. PUR-2021-00097.

[10] *Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia*, Case No. PUR-2020-00031, Exhibit 20.

forecast in this proceeding outpaces the previous year's forecast by seven percent, even accounting for DSM and EE. Given the unprecedented nature of recovery from a global pandemic in the modern economy, Staff acknowledges that forecasts may be more speculative than usual, and valid results may vary more than usual.

The following table presents the actual sales during the period April 2020 through March 2021. The actuals were higher than the Company forecasted last year. However, other than the months of July and August 2020, where the forecasted error exceeded 15 percent and nine percent respectively, the forecast error is within industry accepted bounds of reasonableness for a 12-month projection. Staff notes that unlike the forecasted values for 2020-2021, the actual values will contain the effects of the global pandemic. Even with the effects of the global pandemic, and the measures taken to protect the health and safety of the public, energy sales exceeded the forecasted value by 15 percent, in July of 2020. That demonstrates that it is difficult to attribute a general qualitative impact of the pandemic on energy sales. Thus, it is difficult to accurately incorporate any such impacts into future forecasts.

Month	2020-2021 Forecast (GWh)	2020-2021 Actual (GWh)	Change (%)
April	4,560.9	4,379.1	-4.0%
May	4,851.6	4,795.7	-1.2%
June	5,806.8	5,831.5	0.4%
July	6,382.4	7,360.6	15.3%
August	6,237.7	6,817.3	9.3%
September	5,223.5	5,100.3	-2.4%
October	4,741.1	4,512.8	-4.8%
November	5,125.9	5,024.4	-2.0%
December	6,028.6	6,171.4	2.4%
January	6,463.4	6,627.9	2.5%
February	5,716.8	6,090.8	6.5%
March	5,340.4	5,351.8	0.2%
Total	66,479.3	68,063.4	2.4%

Table 3. Comparison of 2020 Forecasted and Actual Energy Sales[11]

Q7. HOW DOES THE COMPANY FORECAST COMMODITY PRICES?

A7. The Company states that the industry has experienced improved availability and transparency of forward commodity markets, leading to the routine and consistent publication of market-based projections of commodity prices for various fuels, emissions allowances, and wholesale market power.[12] As such, DEV has opted to use observable market forward prices for near term commodity price forecasts. Staff agrees that this is a reliable approach.

The Company's forecasting procedures combine data from existing fossil fuel contracts, conditions of spot, futures, and forward commodity markets as of March 31, 2021, and transportation costs to produce projected monthly estimates of delivered coal, biomass, oil, natural gas, and uranium fuel prices.

[11] *See* DEV Witness Prestage's Schedule 9, Case No. PUR-2021-00097.

[12] Direct Testimony of Company witness Whitney W. Johnson ("Johnson Direct") at 1-2.

Coal

The Company calculates forecasted prices for existing coal contracts by escalating current coal prices, based on predetermined conditions contained within contracts. Market quotes for three distinct product prices are also compiled by the Company: (1) Central Appalachian coal with a 12,500 Btu/lb[13] heat content and 1.6 lb/MMBtu[14] SO_2[15] content using the CSX Corporation railway system; (2) Central Appalachian coal using the Norfolk Southern Corporation railway system; and (3) Northern Appalachian coal with a 13,000 Btu/lb heat content and a 4.0 lb/MMBtu SO_2 content.

Oil and natural gas

Crude and fuel oil prices are forecasted based on the market price for oil futures at the New York Mercantile Exchange Clearport ("NYMEX") and for the West Texas Intermediate crude oil product. Heavy oil prices are based on data from a commonly used broker source Starfuels, Inc. Futures contracts with a delivery point at New York Harbor are used to project prices for No. 2 fuel oil.

Natural gas commodity prices are forecasted based on the market price of Henry Hub NYMEX natural gas futures and market-priced pipeline rates. Natural gas basis price projections are based on Intercontinental Exchange ("ICE") futures prices and S&P Global Platts' analytical posts. Natural gas for DEV's generation fleet is purchased at various market points such as Transco Zone 6NNY,[16] TCO Pool (Columbia Gas Transmission), Dominion South Point (all traded on ICE), and Transco Zone 5 based on Platt's postings.

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[13] British thermal unit per pound.
[14] Pound per million British thermal unit.
[15] Sulfur Dioxide.
[16] Transco 6 Non-New York.

Biomass

DEV has contracted with biomass aggregators for deliveries of wood chips and derivative products to fuel up to 100% of the needs of its existing biomass units. Prices for the wood chips and wood waste that primarily supply these plants are comprised of multiple short-term and long-term contracts form multiple suppliers. All the Company's biomass-burning plants receive wood deliveries via truck.

Nuclear

The Company's nuclear fuel price forecast considers the price of uranium in world markets, along with required conversion, enrichment, and fabrication services (collectively referred to as "front-end components"). Additional expenses for interim spent fuel dry storage and the federal government's charge for the disposal of spent fuel are also included.[17] DEV indicates that the nuclear fuel market has continued to generally soften, even though gradual reductions in excess fuel inventory levels have led to some increases in front-end components. According to DEV, there have been clear world-wide reductions in demand for uranium following the Japanese disaster in March 2011, and the shutdown and announced closings of several reactors in Germany and the U.S. However, supplier reluctance to commence new production and increase enrichment capacity have partly offset such reductions. The soft demand for uranium may not slow and reverse as quickly as anticipated, however, as no Japanese reactors were restarted in 2020 and while China continues its aggressive nuclear energy buildout, which places strain on the global supply

[17] *Nat'lAss'n of Regulatory Util. Comm'rsv. DOE, No. 11-1066* (D.C. Cir. 2013). Pursuant to the U.S. Court of Appeals for the District of Columbia Circuit's decision on November 19,2013, the Department of Energy submitted a proposal to Congress to change the one mill/kWh fee to zero. This reduction took effect on May 16, 2014, and the charge is zero in DEV's projected fuel expenses for the current period.

of uranium, it does not seek front-end component services on the global market and therefore does not impact global prices for these services.

The price of conversion services has begun to lift on the spot market due to production cuts in the United States, and concern over the lack of investment in new conversion facilities and the potential shortfall in capacity. However, Honeywell has announced that it plans to resume operations at its conversion facility in Metropolis, Illinois in 2023. DEV further states that the prices for enrichment services are now relatively stabilized. The Company indicates that trends in fabrication costs are difficult to measure because of the lack of an active spot market. However, DEV states that it expects upward pressure on such costs due to the regulatory requirements and in response to reduced competition and anticipated new reactor demand. Additionally, the parent companies of the two United States nuclear fuel fabricators, Westinghouse and Framatone, continue to experience financial distress which will likely place upward pressure on prices for fabrication and nuclear fuel engineering services. DEV states that it has reduced its exposure to the market price volatility because of its 18-month refueling schedule and active acquisition of some market-based contracts to take advantage of current lower prices.

Emissions

The Environmental Protection Agency's Cross State Air Pollution Rule ("CSAPR") requires states to improve air quality by limiting power plant emissions that cross state lines. The rule spans 28 states requiring reductions in both SO_2 and NO_x[18] emissions.

[18] Nitrogen oxide.

CSAPR permits an emissions allowance-based cap-and-trade program permitting the banking of allowances for use in future years. DEV obtains allowances pricing for SO_2 and NO_x from Evolution Markets, Inc., a commonly used source for environmental pricing data.

Prices contained in Company witness Johnson's Schedule 1 represent the cost per emitted short ton of SO_2 and NO_x allowances available in the market. There are two cap-and-trade markets for NO_x applicable to Virginia: (1) a seasonal program to meet the needs of market participants for the five-month ozone season, May-September; and (2) an annual market for NO_x emissions to comply with CSAPR throughout the year.

The Regional Greenhouse Gas Initiative ("RGGI") is a market-based program to reduce greenhouse gas emissions. It is now comprised of 11 states across New England and the mid-Atlantic regions, including Virginia. Each state has a cap and commitment to reduce carbon dioxide ("CO_2") emissions from the power sector.

Although the carbon allowance is not directly recovered by the fuel factor rate, such allowances affect the way the Company's Virginia-based units are dispatched to meet demand, affecting the ultimate costs incurred.

Participants may purchase allowances during the quarterly auction or trade allowances on the secondary market to offset CO_2 emission. The basis for a market price for a RGGI CO_2 allowance was obtained by DEV from ICE. The forecasted annual price is based on the December contract price obtained from ICE.[19] Previously RGGI allowance prices were sourced from Evolution Markets. The price is also contained in Company witness Johnson's Schedule 1.

[19] Johnson Direct at 6.

Power market

Price projections form the PJM Interconnection, L.L.C. ("PJM") Dominion Zone ("DOM Zone") region were developed using forward price quotes from the PJM Western Hub ("PJM-W") in prior years. These quotes are now directly obtained from ICE-reported forward over-the-counter settlement prices, for both locations.[20]

Q8. WHAT IS YOUR EVALUATION OF THE METHDOLOGY THE COMPANY USED TO FORECAST COMMODITY PRICES?

A8. Staff is familiar with the modeling process described by Company witnesses Whitney and Prestage in their direct testimony. The Company's models and procedures used to forecast commodity prices have been reviewed in previous Commission proceedings, and generally reflect industry conditions and model-building practices. These methodologies employed by the Company to build its forecasting models and prepare forecasts remain acceptable for purposes of this fuel factor proceeding.

As seen in the table below, an average of DEV's projections for fuel prices for last year's fuel factor period were higher than the actual prices realized in the April 2020-March 2021 period. Consistent with recent price outlooks and observations, DEV expects an increase in commodity prices for the 2020-2021 forecast period compared to those forecasted last year. The values shown in the following tables reflect the commodity prices listed in pages 10 and 5 of Company witness Prestage's direct testimony.

[20] Johnson Direct at 6.

COMMODITY	1/31/2020 July 20-June 21	Actual April 20-March 21	Change
Coal (CAPP-FOB) ($/ton)	51.18	44.04	-14%
Oil (Crude-WTI) ($/bbl)	50.81	42.19	-17%
Gas (Henry Hub) ($/mmbtu)	2.27	2.38	5%
Gas (Zone 5) ($/mmbtu)	2.66	2.47	-7%
Gas (Z6NNY) ($/mmbtu)	2.44	2.00	-18%
Power (7x24 PJM West Hub) ($/MWl	26.65	23.62	-11%
Nuclear (expense basis) ($/MWh)	6.14	6.02	-2%

Table 4. Prior Period Forecast and Actual Commodity Prices[21]

COMMODITY	1/31/2020 July 20-June 21	3/31/2021 July 21-June 22	Change
Coal (CAPP-FOB) ($/ton)	51.18	53.88	5%
Oil (Crude-WTI) ($/bbl)	50.81	56.75	12%
Gas (Henry Hub) ($/mmbtu)	2.27	2.75	21%
Gas (Zone 5) ($/mmbtu)	2.66	3.09	16%
Gas (Z6NNY) ($/mmbtu)	2.44	2.66	9%
Power (7x24 PJM West Hub) ($/MWl	26.65	28.49	7%
Nuclear (expense basis) ($/MWh)	6.14	5.97	-3%

Table 5. Prior and Current Period Forward Commodity Price Comparison[22]

The current forecast of commodity prices was based on monthly prices available on March 31, 2021. Staff notes the effect of the global pandemic could have suppressed actuals prices throughout 2020 and into 2021. As such, it would not be unreasonable to expect some rebound in commodity prices as the world and its economy continues to recover from the effects of the global pandemic. Given the unprecedented nature of recovery from a global pandemic in the modern economy, Staff acknowledges that forecasts may be more speculative than usual, and valid results may vary more than usual.

The fact that fuel factors have an embedded annual true-up, however, minimizes the risk of deviation in estimated and actual commodity prices. Based on its overall review,

[21] Prestage Direct at 10.
[22] Prestage Direct at 5.

Staff finds that the Company's forecasts of commodity prices are acceptable for purposes of this fuel factor proceeding.

Q9. HAS THE COMPANY MET THE STANDARDS SET BY THE COMMISSION FOR EVALUATING FUEL COST PROJECTIONS OF ELECTRIC UTILITIES?

A9. In its 1989 Session, the Virginia General Assembly adopted Senate Resolution No. 156, which directed the Commission to establish standards for evaluating fuel cost projections of electric utilities. On November 27, 1990, the Commission adopted such standards and issued its Final Order in Case No. PUE-1990-00004. These standards are provided as Attachment EJW-5 to my testimony. In the present fuel factor proceeding, the Company has complied with those requirements.

Q10. DO YOU HAVE ANY FURTHER COMMENTS ON THE COMPANY'S ENERGY SALES AND COMMODITY PRICES FORECASTS?

A10. No.

Fuel Factor

Q11. WHAT IS THE COMPANY'S UPDATED ESTIMATED JUNE 30, 2021 RECOVERY POSITION?

A11. In response to a Staff interrogatory No. 3-13, the Company provided the actual May 31, 2021 deferred fuel balance of $127.97 million.[23] In its original petition, the Company estimated that its May 31, 2021 deferred fuel balance would be approximately $72.5 million. This an increase of approximately $55 million over the $71.6 million projected in

[23] *See* Company response to Staff Interrogatory No. 3-13, Attachment EJW-6.

the Company's May 13, 2021, original petition and the actual deferred fuel balance on May 31, 2021.

Q12. DESCRIBE ANY CHANGES IN THE COMPANY'S GENERATING UNIT FLEET SINCE THE LAST FUEL FILING.

A12. During the prior period, the Spring Grove 1 Solar Facility, an approximately 98-megawatt ("MW") facility in Surry County, was placed in service November of 2020. The Sadler Solar Facility, an approximately 100 MW facility in Greensville County, was placed in service March of 2021.[24] The Company also contracted for approximately 111 MW of solar capacity from non-utility generators ("NUG") during this time.[25] The Company also expects to place in service the approximately 20 MW Grassfield Solar Facility, located in Chesapeake, by October of 2021.[26] The Company has also installed a 12 MW offshore wind facility off the coast of Virginia Beach.

The Company retired the Possum Point Heavy Oil Unit on December 30, 2020. This generating facility had a capacity of 770 MW.[27] In total, the Company's generating unit fleet is expected to decrease in capability by a net of approximately 440 MW over the current period.

Q13. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PROJECTED NET ENERGY SUPPLY AND GENERATING UNIT PERFORMANCE ASSUMPTIONS FOR THE FORECAST PERIOD.[28]

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[24] Neal Direct at 3.
[25] *Id.*
[26] *Id.*
[27] *Id.*
[28] *See* Company's response to Staff Interrogatory No. 3-11, Attachment EJW-7.

A13. The Company's projected system net energy supply mix and average fuel costs are outlined in Attachment EJW-8. This attachment also presents the Company's historical net energy supply mixes for calendar years 2018 through 2020, and for the 12 months ending March 31, 2021 ("Actual Period"). Attachment EJW-9 provides both the historic and projected Equivalent Availability Factor ("EAF") and Summer Net Capacity Factor ("CF") for each generation fuel type. Finally, Confidential Attachment EJW-10 shows Forecast Period fuel expenses and performance data by facility. The Staff has reviewed the projected EAFs, CFs, unplanned outage rates, planned outages, heat rates, and dispatch costs of the Company's generating resources. Staff concludes that the Company's operational assumptions reflect a reasonable level of performance for fuel expense projection purposes, and are generally consistent with historical performance.

<u>Nuclear Generating Units</u>

During the Forecast Period, DEV's nuclear units have two refueling outages scheduled.[29] The units are expected to be available and run at an approximately 92 percent CF (summer rating) during the Forecast Period. This forecasted performance is within the range of the forecasted performance in recent fuel proceedings, but a slight decrease from the 93 percent CF observed during the Actual Period. Nuclear units account for a similar percentage of the forecasted energy mix as compared to last year, supplying 27.6 million MWh or 30 percent of system net energy supply requirements. In the previous year these units supplied 27.8 million MWh, or 32 percent, of the Company's energy mix.

<u>Coal and Biomass Generating Units</u>

[29] The planned outages are discussed and detailed in Company witness Prestage's Schedule 3.

DEV projects an aggregate EAF of 71 percent and an aggregate CF of 28 percent for its coal-fired, biomass-fired, and coal/wood-fired generating units. During the Actual Period, the aggregate EAF was 62 percent, which is lower than is projected for the Forecast Period. The projected CF of 28 percent is higher than, but within the range of, the CF of 26 percent observed during the Actual Period. The Company estimates that 9.4 million MWh, or 10 percent of its net energy supply, will be generated at these facilities, which compares to 11 percent in the Actual Period.

The Company's remaining large coal-fired units (Chesterfield Units No. 5 and No. 6, the two Clover units, the three Mount Storm units, and the Virginia City Hybrid Energy Center) are projected to achieve an aggregate EAF of 70 percent. These units are also projected to operate at an aggregate CF of 26 percent. During the Forecast Period, four coal units are forecast to have an EAF below 80 percent. Mount Storm 1, a 548 MW coal-fired unit, has a scheduled outage for inspection resulting in an expected EAF of 73 percent. Mount Storm 2, a 553 MW coal-fired unit, has a scheduled outage for inspection resulting in an expected EAF of 67 percent. Chesterfield 6, a 678 MW coal-fired unit, has a scheduled outage for inspection resulting in an expected EAF of 64 percent. In addition, Virginia City Hybrid Energy Center, a 610 MW coal and biomass fired unit, has a scheduled outage for boiler inspection and repair, steam turbine and turbine valve overhauls, and generator inspection and repairs with a projected EAF of 74 percent.

<u>Combined Cycle Generating Units</u>

The Company projects that its natural gas-fired combined cycle units will account for 41 percent of net energy supply, with an aggregate EAF of 77 percent and an aggregate

CF of 83 percent.[30] The combined cycle units are projected to generate approximately 37.4 million MWh. This is approximately a four percent decrease as compared to the 38.9 million MWh generated by natural gas-fired combined cycle units during the Actual Period.

Greensville County, the Company's largest combined cycle unit, has a projected EAF of 79 percent and its projected CF is 82 percent. The facility will have one borescope inspection during the Forecast Period. Brunswick County, the Company's next largest combined cycle unit, is projected to have an EAF of 81 percent and CF of 71 percent. The unit is scheduled to have borescope inspections during the Forecast Period. Warren County, another large combined cycle unit is forecasted to have an EAF of 73 percent and CF of 57 percent. The Warren County plant is scheduled to have a major generator turbine inspection and undergo maintenance of the heat recovery steam generator system during the Forecast Period.

Other Generating Facilities

Oil and natural gas steam generation, Company-owned solar generation, combustion turbine generation, batteries, and hydro generation (net of pumping energy for Bath County) are expected to account for approximately three percent of the Company's total net energy supply. The Company projects an aggregate EAF of 98 percent for its oil and natural gas-fired steam-generating units. During the Actual Period, the Possum Point Heavy Oil unit was retired. The remaining units are projected to continue to operate at a CF of approximately one percent, due to the high cost of oil and relatively low thermal efficiency of the units. This is similar to the CF experienced during the Actual Period.

[30] Staff believes the aggregate CF exceeds the aggregate EAF due to the numbers reported by the Company for Greensville in Attachment EJW-10. Staff was not able to confirm this, however, due to the timing of the discovery.

The Company's combustion turbine facilities are projected to operate at an aggregate CF of six percent, with the majority, approximately 69 percent, of this generation sourced at the Ladysmith and Remington stations. During the Actual Period, these units operated at a slightly higher than forecasted CF of nine percent.

Company-Owned Solar and Wind Facilities

As noted above, during the prior period, the Spring Grove 1 Solar Facility, an approximately 98 MW facility in Surry County, was placed in service November of 2020; and the Sadler Solar Facility, an approximately 100 MW facility in Greensville County, was placed in service March of 2021. Additionally, the Company also placed in service approximately 111 MW of solar capacity from NUGs during this time. During the Forecast Period, the Company expects to place in service the approximately 20 MW Grassfield Solar Facility, located in Chesapeake. The Company has also installed a 12 MW offshore wind facility, off the coast of Virginia Beach.

Recent state policy decisions, particularly the *Grid Transformation and Security Act* and the *Virginia Clean Economy Act*, incentivize large amounts of solar and offshore wind generating capacity being added to the Company's generating portfolio. As these types of generating facilities do not have fuel costs, the amount of energy produced by these facilities can directly offset the Company's fuel expense need and thus affect the Company's fuel factor. Presently, the amount of Company-owned solar and offshore wind capacity remains relatively small; however, in the future this has the potential to change significantly. As such, Staff continues to develop the record in this proceeding and will continue to do so in future fuel factor proceedings.[31]

The Company's responses to Staff Interrogatory Nos. 3-21 and 3-23 provided the projected CF data for the Company-owned solar and offshore wind facilities during the Forecast Period.[32] The Company also projects an average CF of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**percent for its solar facilities during the Forecast Period. The Company projects its offshore wind unit to achieve an average CF of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent during the Forecast Period.[33]

<u>Purchased Power and Off-system Sales</u>

NUG facilities under contract with the Company are projected to achieve a 100 percent aggregate EAF and account for four percent of the Company's net energy supply. DEV also projects that 11 percent of its net energy supply will come from purchases from the PJM energy market.

The Company is projecting net off-system sales ("OSS") to be 283,000 MWh over the Forecast Period. The 75 percent margin will decrease the projected fuel expenses by $16.2 million. During the Actual Period, the Company's OSS were 2.4 million MWh.

Q14. WHAT IS THE PROJECTED AVERAGE FUEL COST OF THE COMPANY'S SYSTEM NET ENERGY SUPPLY?

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[31] In the Forecast Period these resources are projected to provide a total of 951 thousand MWh of generation. In the Actual Period company-owned solar and offshore wind had a combined generation of 1.6 million MWh of generation.

[32] *See* EJW-11.

[33] *Id.*

A14. The average net energy supply fuel cost for the Forecast Period is 1.89 ¢/kWh. This is an increase of 0.07 ¢/kWh, or approximately four percent, from the total average fuel cost of 1.82 ¢/kWh during the Actual Period. The average fuel cost for the calendar year 2020 was 1.73 ¢/kWh.

Q15. DOES THE STAFF PROPOSE ANY ADJUSTMENTS TO THE COMPANY'S PROJECTED FUEL EXPENSES OR FORECAST OF GENERATION PERFORMANCE?

A15. No.

Q16. WHAT ARE YOU CONCLUSIONS?

A16. Staff does not oppose the Company's proposed estimates of energy sales and commodity prices to support its proposed fuel factor in this case. Based on its investigation, the Staff concludes that the Company's projected fuel expenses and the underlying assumptions are reasonable and consistent with the Definitional Framework of Fuel Expenses for Virginia Electric and Power Company (*See* Attachment EJW-12).

Q17. DOES THIS CONCLUDE YOUR TESTIMONY?

A17. Yes.

<u>Virginia Electric and Power Company</u>
<u>Case No. PUR-2021-00097</u>
<u>Virginia State Corporation Commission Staff</u>
<u>Fourth Set</u>

The following response to Question No. 30 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on June 7, 2021 has been prepared under my supervision.

Karim Siamer
Lead Economist,
Load Research and Forecast
Dominion Energy Services, Inc.

Question No. 30

Has the Company changed its methodology for developing its load forecast since the last fuel factor proceeding, Case No. PUR-2020-00031? If so, please provide a detailed narrative describing any changes to the Company's load forecasting methodology to include, but not limited to, any changes in sources of data, list of explanatory variables, *etc.*

Response:

Yes, the Company has changed its methodology for developing its load forecast since the last fuel factor proceeding. The sources of data have not changed; the Company still uses billed sales and economic data as provided by Moody's Economy.com. The table below summarizes notable changes. These changes are with respect to the detailed description of the 2020 load forecasting documentation in Attachment Staff Set 04-29.

Item	2020 Model	2021 Model
End-use Appliances Energy Intensities: combining saturations and stock efficiency.	Source: DNV-GL	EIA Annual Survey Data
Residential Sales Model	Total residential sales were modeled using an econometric equation as described in Attachment Staff Set 04-29 (KS).	Usage per customer was modeled as the independent variable. as opposed to the total sales.
Commercial Model	**2020 Model**	**2021 Model**
Modeling of Datacenter. Customer Choice, Behind the Meter Solar and Net Energy Metering		Modeling of "normalized" class sales taking out the one-off effect of the listed items.
Energy Model	Hourly model	Modeling of "normalized" Monthly Energy taking out the one-off effect of the listed items.
Peak Model	Hourly Model	Modeling of Monthly peak

ATTACHMENT EJW-2

Virginia Electric and Power Company
Case No. PUR-2021-00097
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 14 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on June 4, 2021 has been prepared under my supervision.

Karim Siamer
Lead Economist.
Load Research and Forecast
Dominion Energy Services, Inc.

Question No. 14

Did the Company use data from Moody's Economy.com as the basis for its load and energy forecast? If so, what was the date of the Moody's data? If not, what source was used?

Response:

Yes, the Company did use data from Moody's Economy.com as the basis for its load and energy forecast. The Company used October 2020 vintage.

ATTACHMENT EJW-3

Virginia Electric and Power Company
Case No. PUR-2021-00097
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 17 of the Third Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff received on June 4, 2021 has been prepared under my supervision.

Edmund J. Hall
Energy Market Strategic Advisor
Dominion Energy Services, Inc.

Question No. 17

Company Witness Prestage states on page 5 of her direct testimony that the effects of energy efficiency and demand-side management programs are included in the system sales forecast. Please provide the megawatt-hour impact assumed for demand-side management and energy efficiency. In doing so, please distinguish the megawatt-hour impacts attributable to actual demand-side management and energy efficiency programs approved or pending before the Commission from any assumed megawatt-hour impacts attributable to generic demand-side management and energy efficiency programs.

Response:

See below for the requested information.

Year	Pending & Approved DSM & EE Programs	Generic DSM & EE Programs
2020		1,120,117
2021	190,920	1,146,187
2022	544,939	1,346,574
2023	399,006	1,649,541
2024	1,266,768	1,906,441
2025	1,607,707	1,851,617
2026	1,942,001	1,862,345
2027	2,316,223	1,863,304
2028	2,509,660	1,942,376
2029	2,479,532	1,906,865
2030	2,479,532	1,532,604
2031	2,479,532	1,994,345
2032	2,511,743	2,095,547
2033	2,413,919	2,075,998
2034	2,293,536	2,118,910
2035	2,173,774	2,172,982
2036	2,081,032	2,237,845
2037	1,937,865	2,291,326
2038	1,812,447	2,337,806
2039	1,691,526	2,365,795
2040	145,853	207,041
Total	35,752,606	38,492,024

ATTACHMENT EJW-4

Virginia Electric and Power Company
Case No. PUR-2021-00097
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 15 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on June 4, 2021 has been prepared under my supervision.

Karim Siamer
Lead Economist,
Load Research and Forecast
Dominion Energy Services, Inc.

Question No. 15

Please provide the date when the load and energy forecasts used for this proceeding were completed.

Response:

The load and energy forecasts used for this proceeding were completed in February 2021.

Standards for Fuel Cost Projections of Electric Utilities

- A sophisticated "state-of-the-art" production costing model should be utilized for projecting fuel expenses.

- Key input data and assumptions should reflect historical data. Any significant deviation from historic trends should be adequately explained and evaluated for reasonableness.

- Key input data such as load forecasts, generating unit characteristics, fuel data, and system parameters should be developed in the same relative time period and reflect consistent assumptions.

- Demand forecasts should be current and reflect economic growth, normal weather, the price of electricity, elasticity assumptions, appliance saturations, income, and population changes in the utility's service area. They should also reflect projections of energy, peak demand and the effects of demand-side options.

- Expected fuel prices should reflect historic fuel costs adjusted for any known dynamics of the projection period: i.e., labor contracts, expected operation of the spot market, current fuel contracts in the world fuel market, inventory levels and fuel availabilities, purchasing volumes, coal severance taxes, etc.

- Unit operations should consider planned maintenance, forced outages, expected dispatch levels, historical performance levels, and seasonal capabilities, as well as on-going enhancements or unit deterioration.

- Dispatch order should reflect such variables as system economics, unit availabilities, minimum operating levels, heat rates, and terms and conditions of purchased power contracts.

- Purchase power levels should consider need, system economics, power availability, and transmission constraints.

- Projections supporting the development of cogeneration rates should include a comparison of key input data and assumptions from the last fuel projections filed with the Commission. Major changes should be adequately explained.

<u>Virginia Electric and Power Company</u>
<u>Case No. PUR-2021-00097</u>
<u>Virginia State Corporation Commission Staff</u>
<u>Third Set</u>

The following response to Question No. 13 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on June 4, 2021 has been prepared under my supervision.

Ronnie T. Campbell
Supervisor – Accounting
Dominion Energy Services, Inc.

Question No. 13

Please provide the Company's actual April 2021 and May 2021 cumulative fuel recovery balance positions as they become available.

Response:

See Attachment Staff Set 03-13 (RTC) for an update through May 31, 2021, of Schedule 1 to the pre-filed direct testimony of Company Witness Ronnie T. Campbell dated May 13, 2021. This update shows the Company's actual May 31, 2021, Virginia deferred fuel balance for the current period of $143,542,385.

See Attachment Staff Set 03-13 (RTC) for an update through May 31, 2021 of Schedule 2 to the pre-filed direct testimony of Company Witness Campbell dated May 13, 2021. This update shows the Company's actual May 31, 2021, Virginia deferred fuel balance for the prior period of ($15,569,755).

Adding the two figures above shows an actual May 31, 2021 cumulative deferred Virginia fuel balance of $127,972,630.

Virginia Electric and Power Company
Virginia 2020-2021 Recovery Experience
Eleven Months Ended May 2021

	Allocated Virginia Jurisdiction Fuel Expenses (1)	Cumulative Fuel Expenses (2)	Fuel Revenue Recovery (3)	Cumulative Fuel Revenues Recovery (4)	Current Month Deferral (5)	Balance in Deferral Account (6)
July-20	$ 130,292,196	130,292,196	$ 136,679,359	136,679,359	(6,387,163)	(6,387,163)
August-20	$ 114,176,975	244,469,171	$ 126,590,263	263,269,622	(12,413,288)	(18,800,451)
September-20	$ 78,793,264	323,262,435	$ 94,706,715	357,976,337	(15,913,451)	(34,713,902)
October-20	$ 68,022,920	391,285,355	$ 83,798,749	441,775,086	(15,775,829)	(50,489,731)
November-20	$ 87,316,307	478,601,662	$ 93,297,399	535,072,485	(5,981,092)	(56,470,823)
December-20	$ 128,905,925	607,507,586	$ 114,596,494	649,668,979	14,309,431	(42,161,392)
January-21	$ 137,251,783	744,759,369	$ 123,073,752	772,742,731	14,178,031	(27,983,361)
February-21	$ 156,619,301	901,378,670	$ 113,099,484	885,842,215	43,519,817	15,536,455
March-21	$ 103,935,520	1,005,314,190	$ 37,444,024	923,286,239	66,491,496	82,027,951
April-21	$ 99,098,594	1,104,412,784	$ 72,972,544	996,258,782	26,126,050	108,154,001
May-21	$ 127,970,095	1,232,382,879	$ 92,581,711	1,088,840,493	35,388,384	143,542,385

Virginia Electric and Power Company
Virginia 2020-2021 Fuel Year Recovery Experience
Eleven Months Ended May 2021

	Prior Period Beginning Balance (1)	Revenue Recovery (2)	Adjustments To Prior Period Balance (3)	Fuel Prior Period Ending Balance (4)
July-20	$ (110,468,057) [a]	$ 8,921,072	-	(101,546,985)
August-20	(101,546,985)	$ 11,515,314	-	(90,031,671)
September-20	(90,031,671)	$ 7,895,201	$ -	(82,136,470)
October-20	(82,136,470)	$ 6,985,862	-	(75,150,608)
November-20	(75,150,608)	$ 7,777,714	-	(67,372,894)
December-20	(67,372,894)	$ 9,553,308	-	(57,819,586)
January-21	(57,819,586)	$ 10,260,012	-	(47,559,574)
February-21	(47,559,574)	$ 9,422,067	-	(38,137,507)
March-21	(38,137,507)	$ 8,280,158	-	(29,857,349)
April-21	(29,857,349)	$ 6,574,147	-	(23,283,202)
May-21	(23,283,202)	$ 7,713,447	-	(15,569,755)
Total		$ 94,898,301	$ -	

[a] Fuel Deferral Balance as of June 30, 2020

ATTACHMENT EJW-7

Virginia Electric and Power Company
Case No. PUR-2021-00097
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 11 of the Third Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff received on June 4, 2021 has been prepared under my supervision.

Katherine Farmer
Energy Market Consultant
Dominion Energy Services, Inc.

Question No. 11

Please provide an executable Microsoft Excel spreadsheet with forecast period fuel expense and generating unit performance data by generating unit and power supply fuel type similar to that provided by the Company in Case No. PUR-2020-00031.

Response:

See Attachment Staff Set 03-11 (KF) CONF for the requested information.

Attachment Staff Set 03-11 (KF) CONF contains confidential information as indicated therein, and is being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling issued on May 27, 2021 in this proceeding, any subsequent protective order or ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and the Agreements to Adhere executed pursuant to any such orders or rulings.

ATTACHMENT EJW-8

VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUR-2021-00097
NET ENERGY SUPPLY AND AVERAGE FUEL COST

	System Fuel Expense ($ Millions)	Net Energy Supply (GWh)	Net Energy Supply Mix (%)	Average Fuel Cost (¢/kWh)
Projected 2021 Fuel Year (1)				
Nuclear	165	27,617	31%	0.60
Coal and Wood	252	9,378	10%	2.68
Total Nuclear and Coal	417	36,995	41%	1.13
Combined Cycle	827	37,376	41%	2.21
Other (2)	52	2,391	3%	2.19
Net Purchases				
NUGs	148	3,663	4%	4.05
Market (3)	266	10,121	11%	2.62
Total	1,710	90,546	100%	1.89

(1) July 1, 2021 - June 30, 2022
(2) Fossil Steam Oil & Gas, Combustion Turbines, Hydro, Pumped Storage Net of Pumping Energy, Solar and Batteries
(3) Net of OSS, OSS Margins, and FTRs

	System Fuel Expense ($ Millions)	Net Energy Supply (GWh)	Net Energy Supply Mix (%)	Average Fuel Cost (¢/kWh)
APRIL 1, 2020 THROUGH MARCH 31, 2021				
Nuclear	167	27,807	32%	0.60
Coal and Wood	317	9,558	11%	3.32
Total Nuclear and Coal	485	37,365	43%	1.30
Combined Cycle	753	38,911	45%	1.94
Other (2)	65	2,683	3%	2.44
Net Purchases				
NUGs	107	2,359	3%	4.52
Market (3)	166	5,488	6%	3.02
Total	1,576	86,806	100%	1.82
2020 Actual				
Nuclear	171	28,287	33%	0.60
Coal and Wood	296	8,508	10%	3.48
Total Nuclear and Coal	467	36,795	43%	1.27
Combined Cycle	759	40,826	48%	1.86
Other (2)	57	4,157	5%	1.38
Net Purchases				
NUGs	106	1,176	1%	8.99
Market (3)	111	3,946	5%	2.82
Total	1,500	86,900	102%	1.73
2019 Actual				
Nuclear	173	27,720	33%	0.63
Coal and Wood	273	8,185	10%	3.33
Total Nuclear and Coal	446	35,905	42%	1.24
Combined Cycle	867	37,231	44%	2.33
Other (2)	73	2,214	3%	3.28
Net Purchases				
NUGs	113	2,616	3%	4.31
Market (3)	423	12,992	15%	3.25
Total	1,921	90,957	107%	2.11
2018 Actual				
Nuclear	187	27,360	32%	0.68
Coal and Wood	427	13,503	16%	3.16
Total Nuclear and Coal	614	40,862	48%	1.50
Combined Cycle	951	29,359	35%	3.24
Other (2)	160	3,485	4%	4.60
Net Purchases				
NUGs	193	4,289	5%	4.49
Market (3)	668	14,312	17%	4.67
Total	2,586	92,307	109%	2.80

VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUR-2021-00097
GENERATING UNIT PERFORMANCE ASSUMPTIONS

Aggregate Weighted-Average Equivalent Availability Factors by Generation Fuel-Type
(Percent)

	2016	2017	2018	2019	2020	12 Months Ending Mar-21	PROJECTED 2021 FUELYEAR (1)
Nuclear	92.4	95.2	91.4	92.5	94.2	93.1	**92.2**
Coal and Wood	80.9	76.0	71.7	61.1	69.5	61.5	**70.8**
Heavy Oil (2)	57.5	71.9	66.0	70.3	73.6	75.5	**97.8**
Combined Cycle	81.0	81.4	82.2	75.1	80.8	80.5	**76.8**
Combustion Turbine	92.5	87.6	89.1	87.7	86.9	87.1	**89.6**
Hydro & Bath Co.	80.7	90.3	82.6	85.4	81.6	76.8	**88.6**
NUGs	89.2	94.0	86.6	82.8		-	**100.0**

Aggregate Weighted-Average Capacity Factors by Generation Fuel-Type
(Percent)

	2016	2017	2018	2019	2020	12 Months Ending Mar-21	PROJECTED 2021 FUELYEAR (1)
Nuclear	94.9	97.8	93.5	94.5	96.1	94.8	**94.1**
Coal and Wood	52.4	36.6	35.0	29.1	43.5	26.2	**27.9**
Heavy Oil (2)	1.9	1.1	2.5	1.1	0.9	0.6	**0.9**
Combined Cycle	60.1	62.3	64.5	72.1	77.9	71.1	**83.0**
Combustion Turbine	8.7	6.7	10.3	6.0	11.1	9.2	**5.9**
Hydro & Bath Co.	13.8	14.5	16.9	13.3	14.2	15.8	**16.7**
NUGs	42.2	19.9	26.6	24.8		28.9	**45.0**

(1) July 1, 2021 - June 30, 2022

(2) Includes Natural Gas-fired Units Bremo 3 & 4 and Possum Pt. 3 & 4

ATTACHMENT EJW-10

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Public Version

Attachment Staff Set 03-11 (KF) CON

VIRGINIA ELECTRIC AND POWER COMPANY
PROJECTED FUEL EXPENSE AND GENERATION UNIT PERFORMANCE
JULY 1, 2021 THROUGH JUNE 30, 2022
CASE NO. PUR-2021-00097

	Net Dep. Capacity								[redacted]		
	Summer (MW)	Winter (MW)	Fuel Expense ($000)	Net Generation (000 MWh)	Average Fuel Cost (¢/kWh)	EAF (%)	Average Net MDC CF (%)	Summer Net MDC CF (%)	Average Dispatch Cost (¢/kWh)	Heat Rate (btu/kWh)	Unplanned Outage Rate (%)
NUCLEAR:											
North Anna 1	838	868	[redacted]	[redacted]	[redacted]	89.0	97.5	99.3	[redacted]	[redacted]	[redacted]
North Anna 2	834	863	[redacted]	[redacted]	[redacted]	90.3	87.3	88.8	[redacted]	[redacted]	[redacted]
Surry 1	838	875	[redacted]	[redacted]	[redacted]	91.5	97.8	100.0	[redacted]	[redacted]	[redacted]
Surry 2	838	875	[redacted]	[redacted]	[redacted]	97.8	86.6	88.5	[redacted]	[redacted]	[redacted]
Interim Storage			[redacted]	[redacted]	[redacted]						
Total Nuclear	**3,349**	**3,481**	**164,937**	**27,617**	**0.597**	**92.2**	**92.3**	**94.1**		**10,375**	**2.0**
COAL AND WOOD:											
Large Coal											
Chesterfield 5	336	342	[redacted]	[redacted]	[redacted]	79.8	19.4	19.6	[redacted]	[redacted]	[redacted]
Chesterfield 6	678	690	[redacted]	[redacted]	[redacted]	64.2	16.9	17.0	[redacted]	[redacted]	[redacted]
Clover 1	220	222	[redacted]	[redacted]	[redacted]	86.0	6.8	6.8	[redacted]	[redacted]	[redacted]
Clover 2	219	219	[redacted]	[redacted]	[redacted]	86.0	8.5	8.5	[redacted]	[redacted]	[redacted]
Mount Storm 1	548	569	[redacted]	[redacted]	[redacted]	73.2	38.7	39.4	[redacted]	[redacted]	[redacted]
Mount Storm 2	553	570	[redacted]	[redacted]	[redacted]	67.1	34.8	35.4	[redacted]	[redacted]	[redacted]
Mount Storm 3	520	537	[redacted]	[redacted]	[redacted]	89.0	43.2	43.9	[redacted]	[redacted]	[redacted]
Va. City 1	610	624	[redacted]	[redacted]	[redacted]	45.4	15.2	15.4	[redacted]	[redacted]	[redacted]
Total Large Coal	**3,684**	**3,773**	**216,120**	**8,310**	**2.601**	**70.4**	**25.4**	**25.8**		**10,141**	**7.7**
Total Coal	**3,684**	**3,773**	**216,120**	**8,310**	**2.601**	**70.4**	**25.4**	**25.8**		**10,141**	**7.7**
Wood / Biomass											
Altavista	51	51	[redacted]	[redacted]	[redacted]	82.7	77.9	77.9	[redacted]	[redacted]	[redacted]
Hopewell	51	51	[redacted]	[redacted]	[redacted]	75.7	80.0	80.0	[redacted]	[redacted]	[redacted]
Southampton	51	51	[redacted]	[redacted]	[redacted]	84.6	81.1	81.1	[redacted]	[redacted]	[redacted]
NG transportation			[redacted]	[redacted]	[redacted]						
Renewable Credit			[redacted]	[redacted]	[redacted]						
Total Wood/Biomass	**153**	**153**	**35,584**	**1,068**	**3.332**	**81.0**	**79.7**	**79.7**			
Total Coal / Wood	**3,837**	**3,926**	**251,704**	**9,378**	**2.684**	**70.8**	**27.6**	**27.9**		**10,325**	**7.5**
Total Nuclear and Coal	**7,185**	**7,406**	**416,641**	**36,995**	**1.126**	**80.8**	**57.9**	**58.8**		**10,362**	**4.9**
OIL AND NATURAL GAS:											
Yorktown 3	790	792	[redacted]	[redacted]	[redacted]	97.8	1.6	1.6	[redacted]	[redacted]	[redacted]
NG Transportation			[redacted]	[redacted]	[redacted]						
NG Storage											
NG Hedge Program											
Total Oil and Gas	**1,413**	**1,415**	**9,832**	**113**	**8.679**	**97.8**	**0.9**	**0.9**		**9,826**	**15.3**
COMBINED CYCLE:											
Bear Garden	622	654	[redacted]	[redacted]	[redacted]	77.5	52.9	54.2	[redacted]	[redacted]	[redacted]
Brunswick	1,376	1,470	[redacted]	[redacted]	[redacted]	80.8	70.9	73.3	[redacted]	[redacted]	[redacted]
Chesterfield 7	197	226	[redacted]	[redacted]	[redacted]	78.5	75.2	80.7	[redacted]	[redacted]	[redacted]
Chesterfield 8	195	236	[redacted]	[redacted]	[redacted]	78.3	63.1	69.7	[redacted]	[redacted]	[redacted]
Gordonsville 1	104	122	[redacted]	[redacted]	[redacted]	82.2	61.3	66.6	[redacted]	[redacted]	[redacted]
Gordonsville 2	104	122	[redacted]	[redacted]	[redacted]	66.0	42.7	46.4	[redacted]	[redacted]	[redacted]
Greensville 1	1,588	1,626	[redacted]	[redacted]	[redacted]	78.9	82.0	83.0	[redacted]	[redacted]	[redacted]
Possum Point 6	573	615	[redacted]	[redacted]	[redacted]	64.4	64.6	67.0	[redacted]	[redacted]	[redacted]
Rosemary	160	186	[redacted]	[redacted]	[redacted]	95.9	0.6	0.6	[redacted]	[redacted]	[redacted]
Warren	1,370	1,436	[redacted]	[redacted]	[redacted]	72.8	57.4	58.8	[redacted]	[redacted]	[redacted]
NG Fixed Costs			[redacted]	[redacted]	[redacted]						
Total Combined Cycle	**6,289**	**6,693**	**827,457**	**37,376**	**2.214**	**76.8**	**80.4**	**83.0**		**6,788**	**11.4**

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VIRGINIA ELECTRIC AND POWER COMPANY
PROJECTED FUEL EXPENSE AND GENERATION UNIT PERFORMANCE
JULY 1, 2021 THROUGH JUNE 30, 2022
CASE NO. PUR-2021-00097

CONFIDENTIAL SHADED

	Net Dep. Capacity Summer (MW)	Net Dep. Capacity Winter (MW)	Fuel Expense ($000)	Net Generation (000 MWh)	Average Fuel Cost (¢/kWh)	EAF (%)	Average Net MDC CF (%)	Summer Net MDC CF (%)	Average Dispatch Cost (¢/kWh)	Heat Rate (btu/kWh)	Unplanned Outage Rate (%)
HYDRO & STORAGE											
Cushaw											
Gaston	220	220	[redacted]			100.0	16.6	16.6			[redacted]
Roanoke Rapids	95	95				100.0	34.5	34.5			
North Anna	1	1				100.0	28.9	28.9			
Subtotal Hydro	316	316				100.0	22.0	22.0			
Bath County	1,808	1,808				86.6	15.7	15.7			
Total Hydro	**2,124**	**2,124**		**3,099**		**88.6**	**16.7**	**16.7**			**4.0**
Less Pumping Energy				[redacted]							
Batteries											
Net Hydo / Pump. Stor.				(7)							
COMBUSTION TURBINES:											
Darbytown	336	387	[redacted]			93.9	4.1	4.5	[redacted]		
Elizabeth River	330	365				92.2	4.5	4.7			
Gravel Neck	368	428				86.8	1.3	1.4			
Ladysmith	783	915				88.8	9.7	10.5			
Remington	622	749				89.1	5.7	6.3			
Other	217	308				88.2	0.0	0.0			
NG Transportation			4,885								
NG Storage											
NG Hedge Program											
Total Combust. Turb.	**2,656**	**3,152**	**42,465**	**1,378**	**3.082**	**89.6**	**5.4**	**5.9**		**10,888**	
Total Company Generation	**19,667**	**20,790**	**1,296,395**	**75,855**	**1.709**		**42.8**	**44.0**			
NUG											
Va. Sched19	29	29	[redacted]			100.0	100.0	100.0	[redacted]		
Westvaco	140	140				100.0	100.0	100.0			
Domtar	8	8				100.0	100.0	100.0			
NUG Solar	**753**	**873**	82,518	2,111	3.908						
Total NUGs	**930**	**1,050**	**148,256**	**3,663**	**4.048**	**100.0**	**42.3**	**45.0**			
Purchased Power											
Emergency											
VACARPUR			[redacted]								
Power Hedge Program											
Total Purchases	**0**	**0**	**281,833**	**10,404**	**2.709**						
Company Owned Solar	**306**	**306**	**0**	**907**							
Company Wind	**863**	**863**	**0**	**44**							
Gross Power Supply	**21,766**	**23,009**	**1,726,485**	**90,872**	**1.900**						
Sales			(16,160)	(283)	5.710						
75% OSS Margins			0								
Net Power Supply			**1,710,325**	**90,589**	**1.888**						
Total Fuel Expense			**1,710,325**	**90,589**	**1.888**						

Virginia Electric and Power Company
Case No. PUR-2021-00097
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 21 of the Third Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff received on June 4, 2021 has been prepared under my supervision.

Katherine Farmer
Energy Market Consultant
Dominion Energy Services, Inc.

Question No. 21

Please provide the monthly projected capacity factor and net energy generation for each of the Company's solar units from July 1, 2021 through June 30, 2022.

Response:

See Attachment Staff Set 03-21 (KF) CONF for the requested information.

Attachment Staff Set 03-21 (KF) CONF contains confidential information as indicated therein, and is being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling issued on May 27, 2021 in this proceeding, any subsequent protective order or ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and the Agreements to Adhere executed pursuant to any such orders or rulings.

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[redacted] Attachment Staff Set 03-21 (KF) CONF

Capacity Factor (%)	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
Future Solar	[redacted]											
Partnership Program												
US2_Scott												
US2_Whitehouse												
US2_Woodland												
US-3 CTW												
US-3 SG												
US-4 Sadler												

Generation (GWh)	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
Future Solar	[redacted]											
Partnership Program												
US2_Scott												
US2_Whitehouse												
US2_Woodland												
US-3 CTW												
US-3 SG												
US-4 Sadler												

Virginia Electric and Power Company
Case No. PUR-2021-00097
Virginia State Corporation Commission Staff
Third Set

The following response to Question No. 23 of the Third Set of Interrogatories and Requests for Production of Documents propounded by the Virginia State Corporation Commission Staff received on June 4, 2021 has been prepared under my supervision.

Katherine Farmer
Energy Market Consultant
Dominion Energy Services, Inc.

Question No. 23

Please provide the monthly projected capacity factor and net energy generation for the Company's offshore wind generating units from July 1, 2021 through June 30, 2022.

Response:

See Attachment Staff Set 03-23 (KF) CONF for the requested information.

Attachment Staff Set 03-23 (KF) CONF contains confidential information as indicated therein, and is being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling issued on May 27, 2021 in this proceeding, any subsequent protective order or ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and the Agreements to Adhere executed pursuant to any such orders or rulings.

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[redacted]

Attachment Staff Set 03-23 (KF) CONF

Generation (GWh)	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
Wind_CVOW	[redacted]											

Capacity Factor (%)	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
Wind_CVOW	[redacted]											

VIRGINIA STATE CORPORATION COMMISSION'S DEFINITIONAL FRAMEWORK OF FUEL EXPENSES FOR VIRGINIA ELECTRIC AND POWER COMPANY

a. The cost of fossil fuels shall be those items initially charged to account 151 and cleared to accounts 501, 518 and 547 on the basis of fuel used. In those instances where a fuel stock account (151) is not maintained, e.g., gas for combustion turbines, the amount shall be based on the cost of fuel consumed and entered in account 547.

b. The cost of nuclear fuel shall be the amount contained in account 518, excluding lease finance charges, except that if account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

c. Total energy costs associated with purchased power and charged to account 555 shall be recoverable as fuel costs.

d. Energy revenues associated with off-system sales and recorded in account 447 shall be credited against fuel factor expenses in an amount equal to the total incremental fuel factor costs incurred in the production and delivery of such sales. In addition, seventy-five percent (75%) of the total accumulated energy margins from off-system sales shall be credited against fuel factor expenses annually. In the event such accumulated energy margins result in a net loss, no charges shall be made to fuel factor expenses. Energy margin is defined as the total energy revenue received from an off-system sales transaction less the total incremental costs incurred in supplying that sale.

e. The Company shall be permitted to credit energy revenues associated with Displaced Retail Access Sales against fuel factor expenses in an amount equal to the average fuel factor. No energy margin associated with the sale of the Displaced Retail Access Sales should be credited against fuel factor expenses.

f. All refunds of fuel costs resulting from overcharges, late delivery, or any other reason and all recoveries and adjustments of whatever nature affecting the price of fuel shall be passed on through these proceedings.

g. Company shall be permitted to adjust for system losses through development of a fuel factor based upon fuel costs divided by sales or through the application of a separately derived loss factor applied to a fuel factor based on net energy requirements.