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August 15, 2023

VIA Electronic Filing

Ms. A. Dunston, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: Dominion Energy North Carolina's 2023 Fuel Charge Adjustment
Docket No. E-22, Sub 675

Dear Ms. Dunston:

Enclosed for filing is the *Application for a Change in Fuel Component of Electric Rates* ("Application") of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (the "Company"), in compliance with North Carolina General Statute § 62-133.2 and North Carolina Utilities Commission ("Commission") Rule R8-55. In support of its Application, the Company is filing the Direct Testimony and Exhibits of Jeffrey D. Matzen, James Holloway, Alan J. Moore, Dale E. Hinson, Christopher D. Clemens, and Timothy P. Stuller, as well as Commission Rule R8-55 Information and Workpapers.

Thank you for your assistance with this matter. Please call me if additional information is required.

Very truly yours,

/s/Mary Lynne Grigg

MLG:bms

Enclosures

cc: William E.H. Creech, Public Staff – NC Utilities Commission
William S.F. Freeman, Public Staff – NC Utilities Commission
Lucy Edmondson, Public Staff – NC Utilities Commission

Application, Testimony, and Exhibits of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina

Before the North Carolina Utilities Commission

In the Matter of
Application by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, for Authority to Adjust its Electric Rates and Charges and Revise its Fuel Factor Pursuant to N.C.G.S. § 62-133.2 and NCUC Rule R8-55

Docket No. E-22, Sub 675

Filed: August 15, 2023

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 675

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, for Authority to Adjust its Electric Rates and Charges and Revise its Fuel Factor Pursuant to N.C. Gen. Stat. § 62-133.2 and NCUC Rule R8-55	))))))	APPLICATION FOR A CHANGE IN FUEL COMPONENT OF ELECTRIC RATES

Pursuant to North Carolina General Statutes ("N.C. Gen. Stat.") § 62-133.2 and Rule R8-55 of the Rules and Regulations of the North Carolina Utilities Commission ("Commission"), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or the "Company"), by counsel, hereby applies to the Commission to adjust the fuel component of its electric rates to become effective February 1, 2024, and remain in effect through January 31, 2025. In support thereof, the Company respectfully demonstrates as follows:

1. The Company is a public utility operating in the State of North Carolina as Dominion Energy North Carolina and is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation. As such, the Company's operations in the State are subject to the jurisdiction of the Commission. The Company is also a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. The Company is a wholly-owned operating subsidiary of Dominion Energy, Inc. DENC serves approximately 140,000 customers in North Carolina, with a service territory of about 2,600 square miles in northeastern North

Carolina, including Roanoke Rapids, Albemarle, Ahoskie, Williamston, Elizabeth City, and the Outer Banks. The Company serves major industrial facilities like Nucor Steel, Kapstone, Enviva, and Hospira, as well as commercial and residential customers. The Company's headquarters are located at 120 Tredegar Street, Richmond, Virginia 23219. The post office address of DENC is P.O. Box 26666, Richmond, Virginia 23261.

2. The attorneys for the Company are:

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Lauren W. Biskie
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Copies of all pleadings, testimony, orders, and correspondence in this proceeding should be served upon the attorneys listed above.

3. Pursuant to Rule R8-55(f), the Company is to file its direct testimony, exhibits, and workpapers supporting its fuel adjustment 98 days prior to the hearing. Accordingly, DENC hereby files the direct testimony, exhibits, and workpapers of the following witnesses in support of its proposed fuel adjustment: Jeffrey D. Matzen, James

Holloway, Alan J. Moore, Dale E. Hinson, Christopher D. Clemens, and Timothy P. Stuller.

4. Pursuant to Rule R8-55(c), DENC's test period for this proceeding is the 12-month period ending June 30, 2023 ("Test Period").

5. Updated Rider A and Rider B, as well as Rider B-1 discussed herein, will be in effect for the twelve-month period from February 1, 2024, through January 31, 2025, the proposed "Rate Year."

6. The last general rate case order for the Company was issued by the Commission on February 24, 2020, in Docket No. E-22, Sub 562 ("2019 Base Rate Case Order"). In the 2019 Base Rate Case Order, the Commission reset the Company's system average base fuel factor applicable to the North Carolina jurisdiction to $0.02092/kWh, including regulatory fee ($0.02089/kWh without the fee). The Commission's last fuel adjustment proceeding order for the Company was issued on January 13, 2023, in Docket No. E-22, Sub 644 ("2022 Fuel Order"). The 2022 Fuel Order approved the current Rider A and an updated Experience Modification Factor ("EMF") Rider B. The 2022 Fuel Order also approved the stipulation between the Company, the Public Staff, and CIGFUR 1, in which the parties agreed to the Company's two-step implementation of updated EMF Rider B, to address the significant under-recovery of $66,729,993 that the Company experienced during the previous test period while balancing the impact to customers. Under the two-step mitigation, the Step 1 Rider B rate, which reduced the "Full Recovery" EMF rate, took effect February 1, 2023, through July 31, 2023, and the Step 2 Rider B rate, which recovers the fully supported EMF rate, took effect August 1, 2023, and remains in place.

7. As explained by the direct testimony of Company Witness Matzen, consistent with the methodology applied in the Company's fuel adjustment proceedings dating back to 2008, the Company's cost of fuel calculations are based on the 12-month historical average for fuel prices incurred during the Test Period. As Company Witness Matzen explains, this methodology is a fair representation of the expected expense rates during the February 1, 2024, through January 31, 2025 Rate Year.

8. For the Test Period, the normalized system fuel expense is $3,242,280,682, which is then divided by system sales of 93,914,081,594 kWh, which reflect the normalization adjustments for change in usage, weather, and customer growth. The result is a normalized system average fuel factor of $0.034575/kWh, which is an increase of $0.003864/kWh, applicable to the North Carolina jurisdiction. Company Witness Timothy P. Stuller explains that the Company developed the normalization adjustments for this case using the twelve-month period ended March 31, 2023. This change was made to produce an accurate adjustment in a timely manner for this case due to delayed availability of sales information in the formats required for input to the models that determine changes in usage, weather normalization, and customer growth that have resulted from the Company's transition to a new customer information platform. DENC has under-recovered its fuel costs for the Test Period, after removing underrecovery for July and August 2022 as those months were accounted for in the stipulated EMF in the 2022 fuel adjustment proceeding, by $17,578,384. The total under-recovered fuel expense as of June 30, 2023, based on the current 71% marketer percentage, is provided in the direct testimony and exhibits of Company Witness Alan J. Moore. As Company Witness Dale E. Hinson testifies, this fuel under-recovery was driven by major

commodity price increases created by global geopolitical and energy issues, even while commodity prices have improved significantly in the last six months due to the lack of cold weather during the winter months.

9. The two-step mitigation approved in the 2022 fuel case was expected to leave a significant portion of the original EMF balance from August 31, 2022, unrecovered during the 2023 fuel rate year. In order to separate the under recovery due to mitigation from the recovery of current period expense, which will be recovered through Rider B, the Company is proposing rates to recover the projected remaining balance of the prior period fuel expense, through a mechanism termed "Rider B1," in the 2024 fuel year. In the 2024 fuel proceeding, the Company will establish Rider B1 rates to recover or refund during the 2025 fuel year any final over- or under-recovery of the August 31, 2022 balance.

10. The Company calculated the EMF Rider B and EMF Rider B-1 applicable to the North Carolina jurisdiction and to each customer class using the methodology approved in the 2023 Fuel Order. These calculations are addressed in the direct testimony and exhibits of Company Witness Stuller.

11. The Company proposes that the total fuel rate (base fuel factor, Rider A, EMF Rider B, and EMF Rider B-1) for each class be set as follows, effective February 1, 2024:

Customer Class	Total
Residential	$0.046082
SGS & PA	$0.046038
LGS	$0.045713
Schedule NS	$0.044299
6VP	$0.044937
Outdoor Lighting	$0.046082
Traffic	$0.046082

12. For the North Carolina jurisdiction, the proposed jurisdictional fuel cost levels result in a total fuel recovery decrease of $4,326,317.

WHEREFORE, Dominion Energy North Carolina respectfully requests that the Commission approve the proposed total fuel factor of 4.5609 ¢/kWh, effective February 1, 2024, which shall be allocated based on voltage differentiated adjustments, including the base fuel factor, Rider A, EMF Rider B, and EMF Rider B-1, as follows:

(a) 4.6082 ¢/kWh for the Residential class of customers,
(b) 4.6038 ¢/kWh for the Small General Service and Public Authority classes of customers,
(c) 4.5713 ¢/kWh for the Large General Service class of customers,
(d) 4.4299 ¢/kWh for the Schedule NS class of customers,
(e) 4.4937 ¢/kWh for the Schedule 6VP class of customers, and
(f) 4.6082 ¢/kWh for the Outdoor Lighting and Traffic classes of customers;

and grant any other relief the Commission deems appropriate.

Respectfully submitted, this the 15th day of August, 2023.

DOMINION ENERGY NORTH CAROLINA

By: /s/Mary Lynne Grigg
Counsel for Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina

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akells@mcguirewoods.com

VERIFICATION

NCUC Docket No. E-22, Sub 675

I, J. Scott Gaskill, General Manager – Regulatory Affairs for Virginia Electric and Power Company, do solemnly swear that the facts stated in the foregoing *Application for a Change in Fuel Component of Electric Rates*, insofar as they relate to Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, are true and correct to the best of my knowledge and belief.

Name

COMMONWEALTH OF VIRGINIA)
) to wit:
City of Richmond)

The foregoing instrument was sworn to and acknowledged before me this 14th day of August, 2023.

Notary Public

My registration number is 7684035 and my commission expires:

12/31/2025

DORMECHIA R THOUROGOOD
NOTARY PUBLIC
REG # 7684035
MY COMMISSION EXPIRES 12/31/2025
COMMONWEALTH OF VIRGINIA

DIRECT TESTIMONY OF
JEFFREY D. MATZEN
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 675

Q. Please state your name, business address, and position of employment.

A. My name is Jeffrey D. Matzen, and my business address is 600 E. Canal Street, Richmond, Virginia 23219. I am a Manager in the Strategic Planning Department for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina (the "Company"). I am responsible for forecasting the Company's system energy supply mix, and total system fuel and purchased power expenses. A statement of my background and qualifications is attached as Appendix A.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to present the Company's nuclear and major coal-fired generating unit actual performance, the Company's level of power purchases, and the generation mix for the Company's 12-month test period ended June 30, 2023 ("Test Period"). My testimony describes drivers that affected system fuel expense and the normalization adjustments that impact the expected system fuel expense. I will present the system fuel expenses for the Test Period, and the normalized system fuel expense projected for the rate period February 2024 through January 2025.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit JDM-1, which consists of four schedules, has been prepared under my supervision and is accurate and complete to the best of my knowledge.

Q. Please review the performance of the Company's major generating units for the Test Period.

A. Schedules 1 and 2 of Company Exhibit JDM-1 show the actual monthly and 12-month period ending June 30, 2023, average Equivalent Availability ("EA") and Capacity Factors ("CF") for the Company's nuclear units and large coal-fired units during the Test Period.

During the Test Period, the Company's coal units generated 5,428 GWh of energy. Mt. Storm Units 1-3 performed at EA factors of 63.5%, 72.0%, and 69.7%, respectively. Chesterfield Units 5–6 had EA factors of 46.9% and 57.8%, respectively. Virginia City Hybrid Energy Center ("VCHEC") had an EA of 56.7% during the Test Period.

In regards to what constitutes reasonable nuclear unit performance, Commission Rule R8-55(k) requires that the Company achieve either (a) an actual system-wide nuclear capacity factor in the test year, or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five-year period available as reflected in the most recent North American Electric Reliability Corporation's ("NERC") Generating Availability Report, appropriately weighted for size and type of plant, or a rebuttable presumption of imprudence is created.

The NERC 2017-2021 five-year industry average net capacity factor for Pressurized Water Reactors, which is the most recent available NERC average, is 93.09% for 800-999 MW units. The average capacity factor for the Company's nuclear units for the Test Year and the preceding year was 92.3%, based on the weighted average of the four units at 100% of capacity. The Company's nuclear fleet capacity factor was therefore lower than the industry five-year average for comparable units based on the two-year simple average metric.

The net capacity factors during the historic Test Period for the Company's nuclear units are shown below.

N. Anna 1	91.4%
N. Anna 2	92.7%
Surry 1	87.0%
Surry 2	86.3%

The average capacity factor was 89.4% for the Company's nuclear units for the Test Period. This is based on the weighted average of the four units at 100% of capacity. Based on these figures, the Company's nuclear fleet capacity factor during the Test Period was lower than the industry five-year average for comparable units.

In addition, for the same five-year period, the Company's net capacity factor was 94.6% compared to the national average of 93.09%. Nuclear net capacity factor is one measure of reliable baseload performance and related operating efficiency and is a recognized standard in the energy arena when evaluating nuclear power plant performance. A high net capacity factor reflects an excellent level of reliable baseload operations, which translates into many customer benefits in terms of reduced system fuel cost and consistency in availability. Maximizing generation from this low variable cost baseload resource reflects good operating efficiency and results in overall lower energy costs to customers. Company Witness James Holloway provides additional details regarding the Company's nuclear performance during the Test Period.

Q. What is the expected performance of the Company's nuclear generating units for the 12-month rate period ending January 31, 2025?

A. The projected capacity factors for both North Anna and Surry are expected to be below the most recent NERC five-year average capacity factor of 93.09%. The projected capacity factors are shown below.

N. Anna 1	89.3%
N. Anna 2	100.6%
Surry 1	82.9%
Surry 2	89.7%

The projected weighted average for the nuclear fleet at ownership is 90.9%.

Q. What was the Company's generation mix during the Test Period?

A. The generation mix during the Test Period is shown on Schedule 3 of Company Exhibit JDM-1. Nuclear generation supplied 28.7%; coal-fired generation supplied 5.9%; combined cycle and combustion turbine generation supplied 38.6%; and power transactions (net) supplied 25.0%. These four energy sources accounted for 98.2% of the total energy supply. Oil, biomass, solar and hydro generation provided the remaining 1.8% (net) of the energy supplied.

Q. Please describe the major drivers that affected the $/MWh average fuel expense during the Test Period.

A. The Company continues to experience a significant under-recovery of fuel expenses during the test year. As described by Company Witness Dale E. Hinson, this fuel under-recovery was driven by previous major commodity price increases created by global geopolitical and energy issues, although commodity prices have improved significantly in the last six months due to the lack of cold weather during the winter months.

Q. Does the Company propose to normalize nuclear capacity factor levels in determining an appropriate fuel factor in this proceeding?

A. Yes. Because the Company's projected nuclear generation during the upcoming rate year is expected to be slightly higher than the actual generation during the Test Period, we have normalized expected nuclear generation and fuel expenses using the expected nuclear capacity factors shown above for the

12-month period ending January 31, 2025, in developing the proposed fuel cost rider in this proceeding.

Q. Please describe the Company's normalization of system fuel expenses.

A. Schedule 4 of Company Exhibit JDM-1 illustrates an expense normalization methodology that has been used by the Company and approved in previous North Carolina annual fuel factor proceedings. The first step in computing normalized system fuel expenses is to calculate nuclear generation based on the expected future operating parameters for each unit. The expected generation from the nuclear units was calculated for the 12-month period ending January 2025. Other sources of generation were then normalized for the Test Period. The total of coal, heavy oil, combustion turbine and combined cycle and purchased energy during the Test Period was then calculated. A percentage of this total was then calculated for each of the above resources. Normalized generation was computed by applying these percentages to a new total, which includes an adjustment for weather, customer growth, increased usage, and the net change in nuclear and "Company" solar generation. This methodology for normalizing the Test Period generation, as described by Company Witness Stuller, resulted in adjusted annual system energy requirements of 96,483,136 MWh, an increase of 4,830,893 MWh from the actual energy requirements for the 12 months ended June 30, 2023.

Q. Please describe any major changes to the generation fleet or regulatory changes that will impact the system fuel expense.

A. During the Test Period, the Grassfield Solar Facility, an approximately 20 MW (AC) facility, and the Renan Solar Facility, an approximately 42 MW (AC) facility, were placed in service. There was an additional 20 MW (AC) of PPA solar placed in service.

The Company anticipates adding additional solar facilities totaling approximately 953 MW (nominal alternating current ("AC")) during the rate period. The Company anticipates a benefit to system fuel expense from these changes and an adjustment of $37.3 million has been included on my Schedule 4 showing the calculation of the system projected fuel expense.

Q. Has the Company evaluated the current marketer percentage calculation?

A. Yes. The system fuel expense includes PJM Interconnection, LLC ("PJM") energy market purchases, NUG energy purchases and off-system sales. Generally, purchases from the PJM energy market and certain NUG purchases do not provide fuel cost data. The marketer percentage is a proxy used to approximate the percentage of these purchase costs related to fuel and is applied to these fuel expenses. Consistent with the Commission's conclusions in the 2019 general rate case, Docket No. E-22, Sub 562, the Company has updated the calculation of the marketer percentage based on the PJM State of the Market Reports for 2021 and 2022, using the same averaging method that was applied in the 2022 fuel case as well as the Company's 2019 general rate case. The updated marketer percentage is 68% and a line-item adjustment of $41.3 million has been included on my Schedule 4 showing the calculation of the system projected fuel expense.

Q. Please describe the other fuel expense normalization items.

A. The results of the Avoided Cost ("Blend and Extend") proceeding created an option for modified purchase agreement terms for eligible small power producers. One facility notified the Company of its intent to participate in this modified treatment. The unit has a capacity rating of five MW. The projected fuel savings would be approximately $200,000 per year. This adjustment is included in my Schedule 4.

The $/MWh expense rates for all fuel types are based on the actual 12-month average expense rates incurred during the Test Period. Using the 12-month average rate for these commodities is consistent with the methodology used in the 2008–2022 fuel cases and is a fair representation of the expected expense rates during the February 2024 – January 2025 rate period.

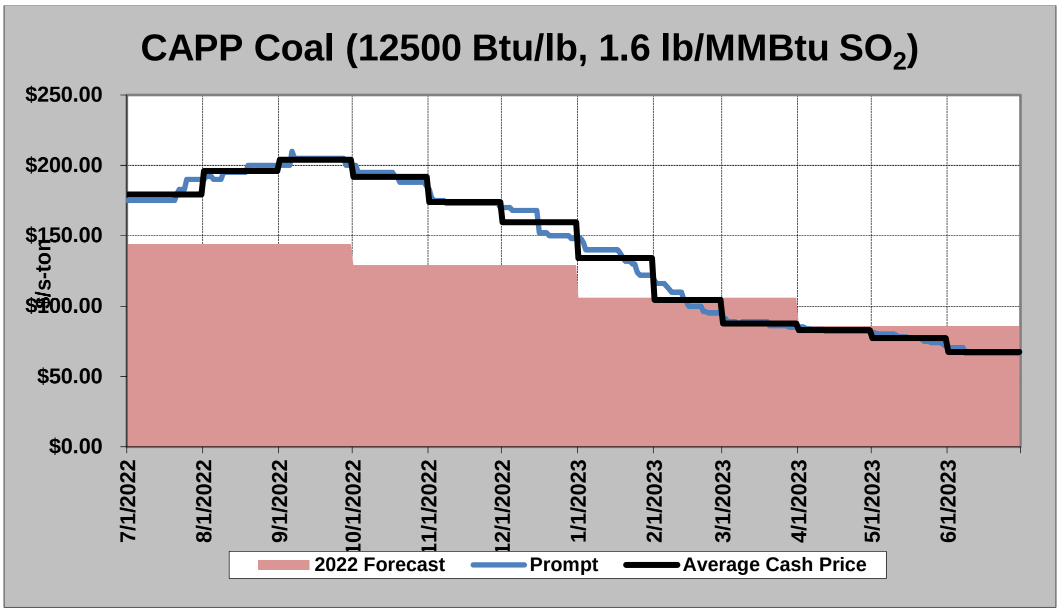
Q. What is the resulting normalized system fuel expense?

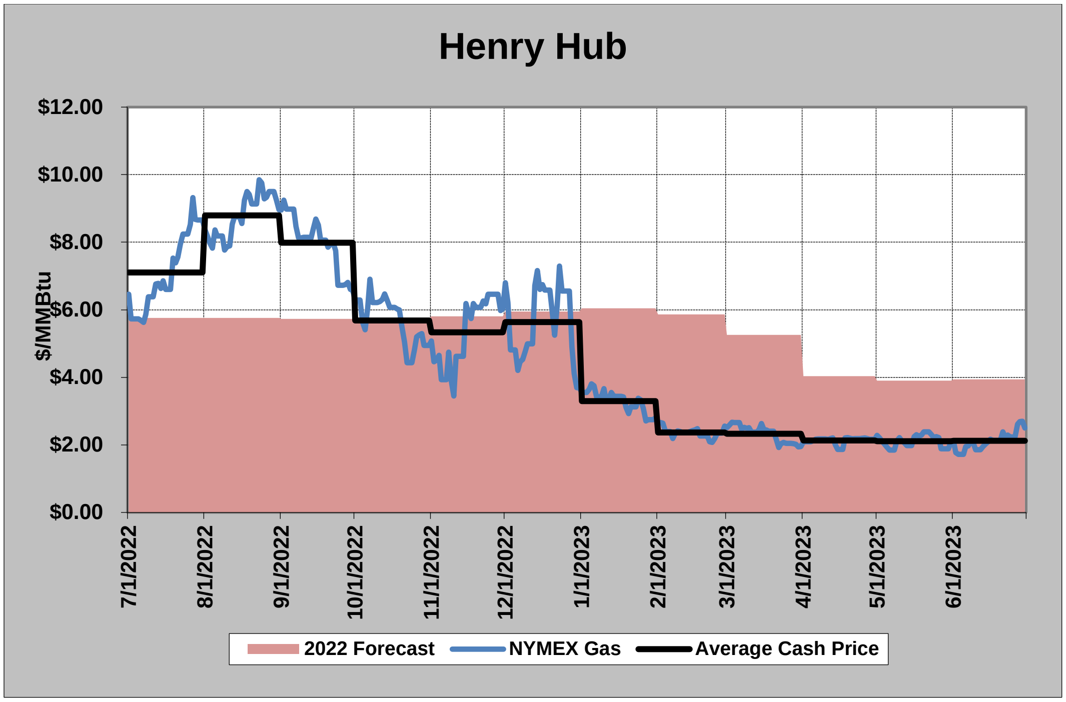
A. As shown by Schedule 4, which also presents the detailed calculations in support, the resulting normalized system fuel expense is approximately $3.24 billion.

Q. Please summarize how commodity prices varied over the Test Period.

A. The graphs below show the actual spot commodity prices during the Test Period. All commodity prices trended downward during the Test Period.

Company Witness Hinson describes the Company's coal and natural gas buying practices, which determine the actual coal and natural gas expenses. Spot power prices have also decreased but have shown some volatility during the Test Period. The charts indicate some weather-related natural gas and power price spikes.





Henry Hub
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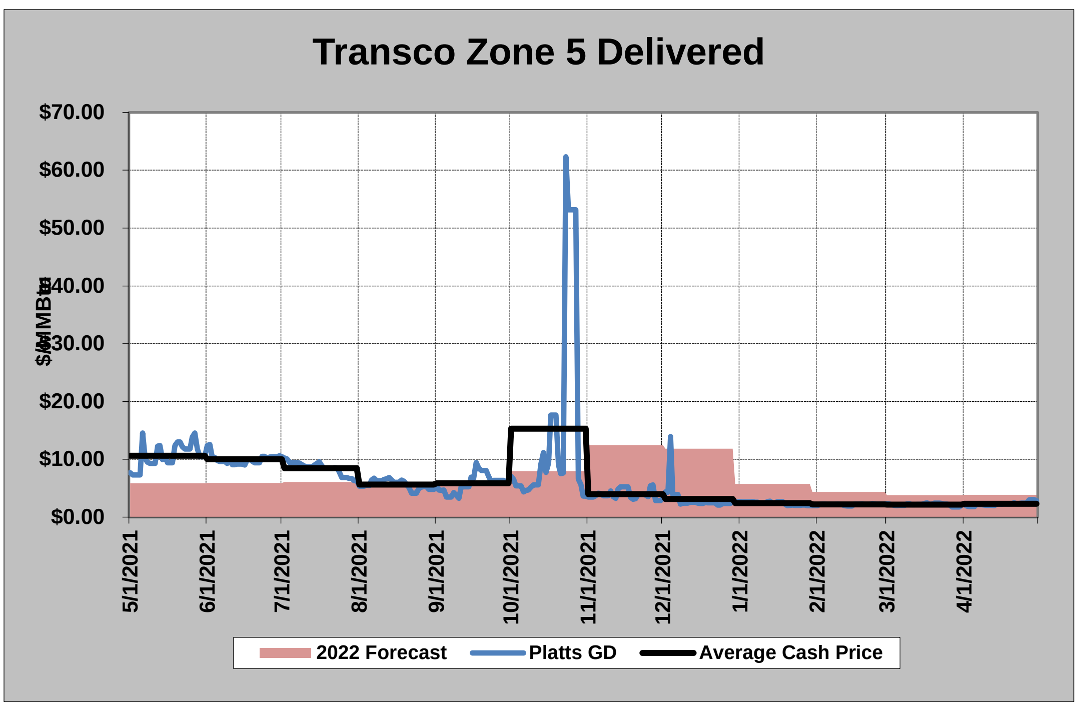
$8.00
$6.00
$4.00
$2.00
$0.00
$/MMBtu
7/1/2022
8/1/2022
9/1/2022
10/1/2022
11/1/2022
12/1/2022
1/1/2023
2/1/2023
3/1/2023
4/1/2023
5/1/2023
6/1/2023
2022 Forecast
NYMEX Gas
Average Cash Price



Transco Zone 5 Delivered
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$60.00
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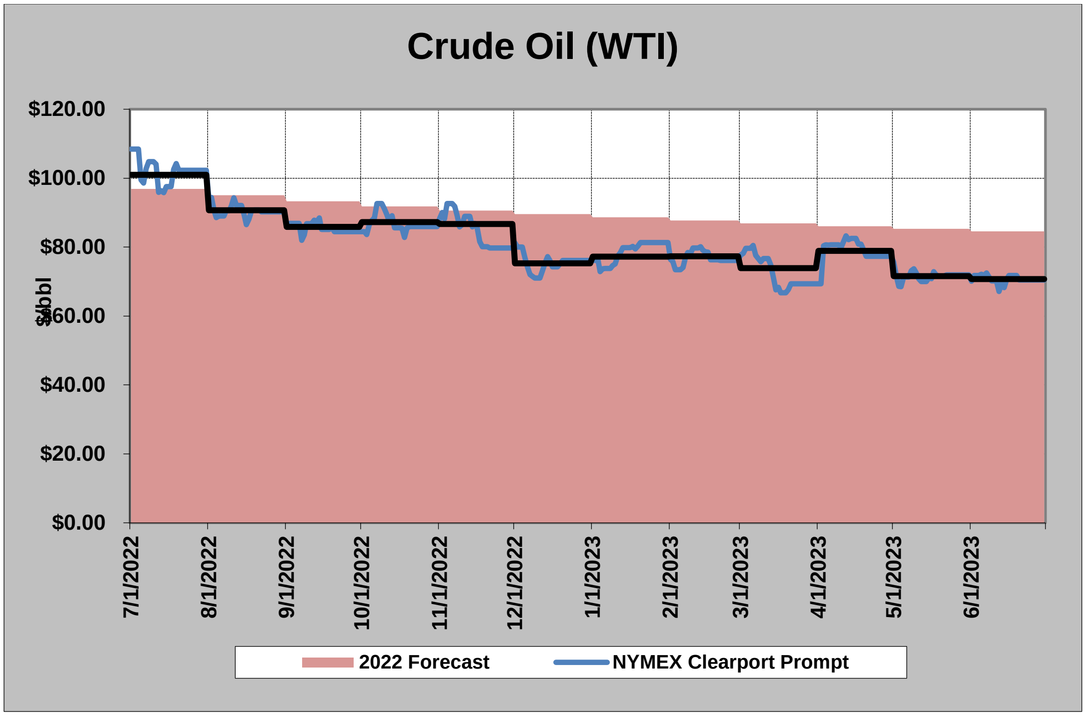
$40.00
$30.00
$20.00
$10.00
$0.00
$/MMBtu
5/1/2021
6/1/2021
7/1/2021
8/1/2021
9/1/2021
10/1/2021
11/1/2021
12/1/2021
1/1/2022
2/1/2022
3/1/2022
4/1/2022
2022 Forecast
Platts GD
Average Cash Price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$/bbl
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8/1/2022
9/1/2022
10/1/2022
11/1/2022
12/1/2022
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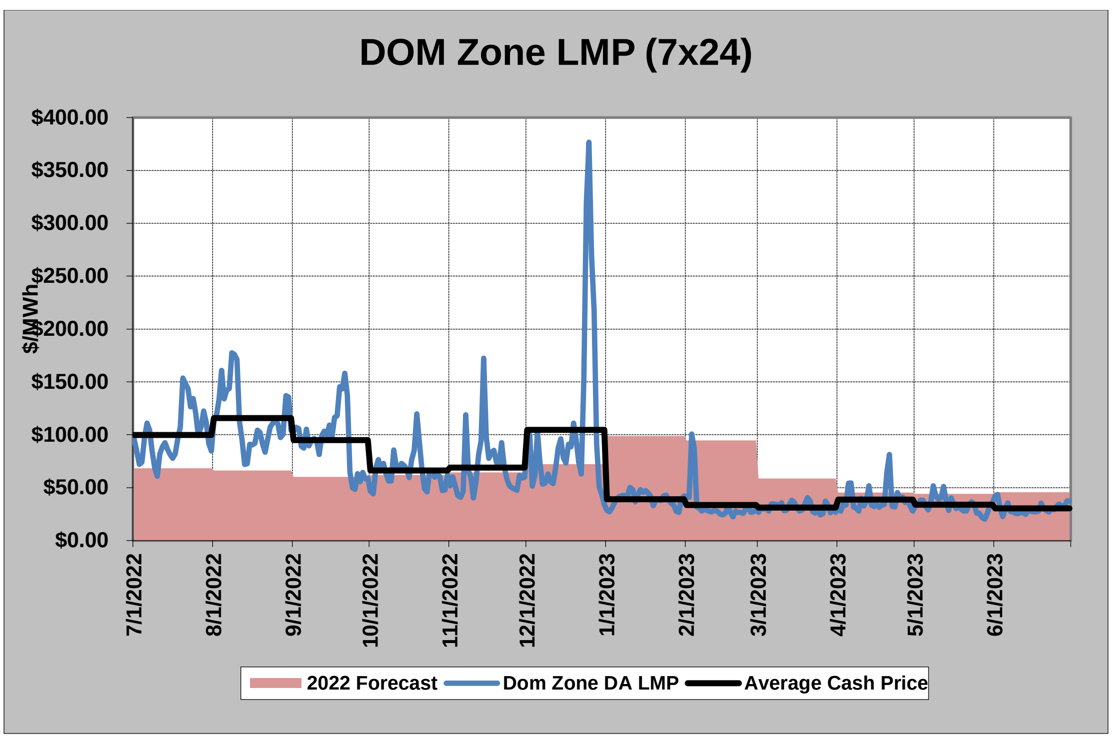
2022 Forecast
NYMEX Clearport Prompt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$300.00
$250.00
$200.00
$150.00
$100.00
$50.00
$0.00
$/MWh
7/1/2022
8/1/2022
9/1/2022
10/1/2022
11/1/2022
12/1/2022
1/1/2023
2/1/2023
3/1/2023
4/1/2023
5/1/2023
6/1/2023
2022 Forecast
Dom Zone DA LMP
Average Cash Price

Q. Mr. Matzen, does this conclude your direct testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS
OF
JEFFREY D. MATZEN

Jeffrey D. Matzen graduated from Virginia Tech in 1996 with a Bachelor of Arts degree in Economics. In 2001 he earned Master of Business Administration and Master of Public Policy degrees from the College of William and Mary. He joined the Company in 2007 as an Electric Pricing and Structuring Analyst. He has since held positions at the Company as an Energy Consulting Manager for Retail, a Business Modeling & Support Consultant for Alternative Energy Solutions, and a Market Operations Advisor for Energy Supply. In January 2020, Mr. Matzen was promoted to Manager of Generation System Planning where he is currently responsible for the Company's short-term operational forecast (PLEXOS model). Prior to joining Dominion, Mr. Matzen worked for Wells Fargo Advisors as an analyst and the Virginia Department of Taxation as an economist.

Mr. Matzen has previously submitted testimony before the State Corporation Commission of Virginia and the North Carolina Utilities Commission.

DOMINION ENERGY NORTH CAROLINA
EQUIVALENT AVAILABILITY FACTORS (%)
NUCLEAR AND LARGE COAL UNITS

July 2022-June 2023

	Nuclear Units				Large Coal Units					
	North Anna		Surry		Mt. Storm			Chesterfield		VaCity
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2	Unit 3	Unit 5	Unit 6	Unit 1
Jul-22	99.8%	100.0%	99.0%	99.5%	69.8%	63.9%	86.8%	30.8%	70.3%	76.7%
Aug-22	99.8%	41.5%	98.6%	99.4%	80.9%	78.8%	43.0%	41.5%	61.3%	70.6%
Sep-22	63.6%	39.8%	99.1%	99.9%	13.3%	99.7%	89.6%	16.7%	49.5%	5.0%
Oct-22	12.6%	100.0%	86.7%	100.0%	0.0%	99.7%	58.1%	18.2%	93.3%	0.0%
Nov-22	99.8%	100.0%	0.0%	100.0%	50.7%	99.7%	0.0%	65.5%	64.3%	71.0%
Dec-22	100.0%	100.0%	45.0%	100.0%	42.9%	95.4%	81.6%	71.2%	39.3%	95.9%
Jan-23	100.0%	100.0%	100.0%	95.0%	99.3%	48.4%	84.8%	95.8%	90.8%	78.8%
Feb-23	100.0%	100.0%	100.0%	100.0%	83.5%	100.0%	95.7%	43.8%	12.9%	92.3%
Mar-23	100.0%	100.0%	100.0%	99.2%	99.8%	82.7%	53.0%	31.0%	27.9%	0.0%
Apr-23	100.0%	100.0%	100.0%	70.7%	100.0%	0.0%	79.3%	56.4%	57.1%	7.5%
May-23	100.0%	100.0%	100.0%	0.0%	37.1%	20.1%	85.9%	56.4%	64.9%	99.7%
Jun-23	100.0%	100.0%	99.9%	45.8%	86.4%	77.9%	80.5%	N/A*	N/A*	83.8%
12-Month Average	89.5%	90.3%	85.7%	84.1%	63.5%	72.0%	69.7%	46.9%	57.8%	56.7%

*Chesterfield Units 5 and 6 retired May 31, 2023

DOMINION ENERGY NORTH CAROLINA
NET CAPACITY FACTORS (%)
NUCLEAR AND LARGE COAL UNITS

July 2022-June 2023

	Nuclear Units				Large Coal Units					
	North Anna		Surry		Mt. Storm			Chesterfield		VaCity
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2	Unit 3	Unit 5	Unit 6	Unit 1
Jul-22	99.8%	100.0%	99.0%	99.6%	38.9%	34.4%	45.5%	16.4%	22.3%	55.1%
Aug-22	99.4%	41.9%	98.6%	99.6%	24.1%	35.1%	10.8%	20.6%	30.1%	38.7%
Sep-22	63.6%	39.8%	99.5%	100.9%	7.1%	22.1%	12.3%	6.6%	11.0%	1.7%
Oct-22	13.5%	103.3%	87.2%	103.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nov-22	102.8%	103.6%	0.0%	104.4%	18.8%	9.6%	0.0%	17.6%	19.8%	0.5%
Dec-22	103.3%	104.0%	46.4%	104.4%	19.7%	43.7%	48.7%	28.3%	19.9%	36.5%
Jan-23	103.1%	103.9%	103.2%	98.5%	21.2%	14.5%	0.0%	1.2%	0.0%	28.8%
Feb-23	103.2%	103.8%	103.0%	104.1%	8.9%	12.5%	67.5%	42.6%	7.1%	22.0%
Mar-23	102.9%	103.5%	102.8%	103.8%	50.3%	59.4%	5.5%	5.3%	27.5%	0.0%
Apr-23	102.5%	103.2%	102.0%	66.1%	2.1%	0.0%	48.6%	3.2%	29.2%	3.3%
May-23	102.3%	103.0%	102.1%	0.0%	25.6%	10.2%	34.7%	0.0%	0.0%	18.4%
Jun-23	101.9%	102.4%	100.5%	51.7%	28.0%	31.9%	34.0%	N/A*	N/A*	0.0%
12-Month Average	91.4%	92.7%	87.0%	86.3%	20.6%	22.9%	25.3%	12.7%	15.2%	17.2%

*Chesterfield Units 5 and 6 retired May 31, 2023

DOMINION ENERGY NORTH CAROLINA
SYSTEM ENERGY SUPPLY

Actual 12-Month Ended June 2023

	Generation (MWhs)	% of Energy Supply
Nuclear	26,267,045	28.7%
Coal	5,427,959	5.9%
Heavy Oil	15,552	0.0%
Wood	1,084,142	1.2%
Combined Cycle and Combustion Turbine	35,360,623	38.6%
Solar, Wind and Hydro - Conv and Pumped Storage	3,809,582	4.2%
Net Power Transactions	22,958,681	25.0%
Less Energy for Pumping	(3,271,343)	-3.6%
Total System	91,652,242	100.0%
Nuclear, NG, Coal and Net Power Transactions		98.2%

Dominion Energy North Carolina
Docket No. E-22, Sub 675

Company Exhibit JDM-1
Schedule 4
Page 1 of 1

DOMINION ENERGY NORTH CAROLINA
ENERGY AND FUEL EXPENSES

Normalized and Adjusted Energy and Fuel Expense based on Actual 12-Months Ended June 2023
(Company Ownership Only)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)
	12-Months Ended June 2023							June 2023				
	Expense ($)	Generation (MWh)	Rate ($/MWh)	Supply (%)	Ratio of Coal CT & CC & Other MWH To Total Sum	Coal, Oil, CT & CC, Other, Nuclear Adj. and Growth MWh	Adjusted Generation (MWh)	Expense ($)	Generation (MWh)	Rate ($/MWh)		Normalized & Adjusted Fuel Expense at Applicable Rate (8) x (11)
Coal (1)	275,837,306	6,512,101	42.36	7.1	0.1048	65,809,527	6,898,944	22,717,262	458,862	42.36	(4)	292,239,268
Nuclear												
Surry	76,889,991	13,483,876	5.70	14.7			12,671,140	6,280,917	922,551			
North Anna	76,817,661	12,783,170	6.01	13.9			13,910,410	6,501,472	1,229,589			
Total Nuclear	153,707,653 (3)	26,267,045	5.85	28.7			26,581,550	12,782,389	2,152,140	5.85	(4)	155,502,068
Heavy Oil	743,460	15,552	47.80	0.0				0	0	47.80	(4)	0
CC & CT (2)	1,592,368,933	35,360,623	45.03	38.6	0.5692	65,809,527	37,461,349	68,000,622	3,247,848	45.03	(4)	1,686,884,545
Hydro	0	3,012,451		3.3			3,012,451	0	323,810			0
Solar	0	797,131		0.9			1,638,661		79,290			
Power Transactions												
PPA Fuel	170,768,837	2,712,291	62.96	3.0			2,712,291	13,557,798	263,173	62.96	(4)	170,768,837
PPA Blend and Extend Adj												200,000
PJM Purchases	923,164,892	20,246,390	45.60	22.1	0.3259	65,809,527	21,449,233	15,009,851	1,796,597	45.60	(5)	978,010,345
Marketer Percentage Adjustment (68%)										-1.93		(41,324,381)
Net	1,093,933,729	22,958,681	47.65	25.1			24,161,524	28,567,648	2,059,770			1,107,654,801
Pumping	0	(3,271,343)		-3.6			(3,271,343)	0	(374,730)			0
Energy Supply	3,116,591,080	91,652,242	34.00	100.0			96,483,136	132,067,922	7,946,990	33.60		3,242,280,682

NOTE: ALL VALUES REFLECT COMPANY'S OWNERSHIP OF NORTH ANNA, CLOVER AND BATH COUNTY

(1) Coal includes wood generation
(2) CC & CT includes jet oil, light oil and natural gas generation
(3) Nuclear expense excludes interim storage
(4) Fuel expense rate based on weather normalized fuel expense
(5) Purchases include 71% of the fuel expense and the impact of the FTRs

DIRECT TESTIMONY OF
JAMES HOLLOWAY
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 675

Q. Please state your name, business address, and position of employment.

A. My name is James Holloway, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am the Vice President of Nuclear Engineering & Fleet Support for Dominion Energy, Inc. ("Dominion Energy"). I am testifying on behalf of Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina (the "Company"). I have accountabilities for all facets of engineering support of the Company's nuclear fleet, including North Anna Nuclear Power Station, located in Mineral, Virginia ("North Anna Power Station") and Surry Nuclear Power Station, located in Surry, Virginia ("Surry Power Station").

Q. What are your responsibilities as Vice President of Nuclear Engineering & Fleet Support?

A. As Vice President of Nuclear Engineering & Fleet Support, I am responsible for all engineering activities of the Company's nuclear stations in Virginia and Dominion Energy's other nuclear stations, including Millstone Nuclear Power Station located in Waterford, Connecticut and Virgil C. Summer Nuclear Power Station located in Jenkinsville, South Carolina. I have accountability for the Dominion Energy nuclear fleet corporate regulatory affairs, including nuclear licensing, emergency preparedness, North American Electric Reliability

Corporation ("NERC") compliance, and the Subsequent License Renewal ("SLR") project team.

Q. Have you previously testified before this Commission?

A. No.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to describe the performance of the North Anna and Surry Power Stations during the period of July 1, 2022, through June 30, 2023 (the "Test Period"). I also discuss the outages that occurred at these stations during the Test Period. Finally, I provide information regarding the Company's SLR projects and how SLR will impact future refueling and maintenance outages at both North Anna and Surry Power Stations.

Q. Please describe the Company's Nuclear Generation fleet.

A. The Company's nuclear fleet consists of two generating stations, North Anna and Surry Power Stations ("Nuclear Fleet") with a total generating capacity of approximately 3,568 total megawatts ("MW"), composed of:

North Anna - 1,892 MW (88.4% ownership); and

Surry - 1,676 MW.

The North Anna and Surry Power Stations are both pressurized water reactor facilities with two units each. North Anna Power Station Unit 1 and Unit 2 began commercial operation in 1978 and 1980, respectively.

The operating licenses for North Anna Power Station were renewed by the Nuclear Regulatory Commission ("NRC") in 2003, extending operations up to

2038 and 2040 for Units 1 and 2, respectively. In 2020, the Company submitted an SLR application to the NRC to extend the operating license of North Anna Power Station by 20 additional years.

Surry Power Station Units 1 and 2 began commercial operation in 1972 and 1973, respectively. The operating licenses for Surry Power Station were renewed by the NRC in 2003 extending operations up to 2032 and 2033 for Units 1 and 2, respectively. In 2021, the NRC approved a subsequent license renewal for Surry Power Station further extending operations by another 20 years to 2052 and 2053 for Units 1 and 2, respectively.

Q. What are the Company's primary objectives in the operation of its Nuclear Fleet?

A. The Company's primary objectives in the operation of its Nuclear Fleet are to safely, reliably, and efficiently generate electricity to improve the quality of life for the Company's communities, and to protect and sustain a clean energy future. The Company achieves these objectives by focusing on several key elements including superior safety standards, reliable plant operations, valued and engaged employees, expert technical knowledge and skills, innovative advances to improve performance, and environmental responsibility and community involvement.

Q. Please discuss the Nuclear Fleet's performance during the Test Period.

A. The Nuclear Fleet operated at an actual system average capacity factor of 89.40% during the Test Period, which included three refueling outages, two forced outages, and one planned maintenance outage. I discuss each of these events in further detail below.

Q. How does the Nuclear Fleet's performance compare to the industry average?

A. As discussed in the direct testimony of Company Witness Jeffrey Matzen, the most recently published NERC Generating Unit Statistical Brochure indicates an industry average capacity factor of 93.09% for comparable units for the five-year period of 2017 through 2021. The Nuclear Fleet had a Test Period capacity factor of 89.40%, and two-year average capacity factor of 92.30%. Over the five-year period from 2017-2021, the Nuclear Fleet operated at a 94.6% capacity factor.

Q. Was the Company prudent in its operations of the Nuclear Fleet considering this performance?

A. Yes, the Company operated its Nuclear Fleet in a reasonable and prudent manner during the Test Period. Capacity factor is just one metric that is used when determining if the Company's Nuclear Fleet operated prudently. Both North Anna and Surry Power Stations have sustained high levels of plant performance and operated in a safe and reliable manner while maximizing generation. This included during Winter Storm Elliott in December 2022, when both stations exceeded capacity expectations when needed the most during the cold weather conditions. The Company's nuclear power stations provide baseload power during cold weather events. Cold weather protection measures are proactively put in place ahead of the winter season. These measures are outlined in robust procedures which ensure pro-active equipment preparation and enhanced routine/daily inspections. This cold weather preparation and daily engagement allowed the North Anna and Surry Power Stations to operate flawlessly through Winter Storm Elliott.

Additionally, as I noted previously, over the five-year period from 2017-2021, the Company's Nuclear Fleet operated at a 94.6% capacity factor, which is above the NERC five-year average.

Q. How does the Company schedule and manage the impact to unit availability of refueling and maintenance outages for the Nuclear Fleet?

A. The major factors that affects a unit's availability are maintenance and refueling. When scheduling refueling and maintenance outages, the Company's main goal is to maximize plant operational safety, reliability, and availability. In certain cases, the Company schedules overlapped Nuclear Fleet outages to support efficient deployment of shared and supplemental resources.

The Company uses long-range planning to develop, prioritize, and establish major projects and key activities to be completed in future outages. The outage plan reflects the station's long-range plan and encompasses several refueling cycles, typically for the next five to seven years. The activities conducted during outages may be driven by improvement projects, design changes, preventative maintenance, regulatory required testing and inspections, system health items, or other required regulatory commitments and obligations. The Company conducts outage scheduling for refueling and maintenance in a systematic manner to ensure that all planned activities are performed and all scheduled repairs are completed. The Company strives to execute scheduled outages according to the planned duration while successfully implementing projects that are within the outage scope.

Q. You mentioned the SLR requests the Company has made for the Nuclear Fleet. Please elaborate.

A. When the Company decided to apply for the renewed licenses to extend the operating lives of its Nuclear Fleet, one of the first tasks was to assess which structures, systems and components would be acceptable for continued operation beyond 60 years and which ones would need to be evaluated for potential replacement to ensure safe and reliable operation up to 80 years. The Company gathered its own experts, engineers, project managers, and other station personnel with decades of experience in design, licensing and operation of nuclear plants and also sought advice from external industry experts to identify the projects that are most essential to ensure extended operating lives.

Due to the complexity of and regulatory requirements applicable to implementing projects at an operating nuclear facility, the Company knew the execution of these projects from conceptual design through the project life cycle would require highly detailed, complex planning and choreography. The majority of the work will be performed during planned outages, during which minimizing the duration is critical and other units at the sites are in operation at the same time, without compromising safety and quality standards.

The Company established an SLR program in 2017. The program consists of 19 projects at Surry and 15 projects at North Anna, including 12 projects common to both plants. These SLR projects are included in the Company's long-range outage plan for the Nuclear Fleet and include projects essential to ensure the units are operated in a safe and reliable manner during the extended license period from 60 to 80 years. These projects range in size and complexity and include complicated station design changes and modifications. Examples of some of the common projects are main electrical generator replacement, main control room modernization, polar crane replacement, and fuel handling system replacement. In certain cases, the projects will entail replacing or upgrading certain equipment, such as generators, exciters, and automatic voltage regulators ("AVRs") that has continued to operate successfully into the initial license renewal period of 40-60 years based on the original design margins, proper design, and effective maintenance strategies, and that needs attention or replacement to continue to successfully operate in the subsequent license renewal period of 60 to 80 years. Many of the projects will be implemented during planned refueling outages over the next decade and are anticipated to directly impact outage duration.

Q. What impact does SLR have on planned refueling outages?

A. The Company expects that implementation of SLR activities will impact the capacity factor of the North Anna and Surry Power Stations, where the capacity factor in some Test Periods during the next few years will likely be less than the five-year period NERC average. The long-range outage plan accounts for SLR projects and distinguishes the incremental outage days for SLR.

Q. Is the potential for extension of planned refueling and maintenance outages for SLR activities reflected in the NERC Brochures?

A. No. The extension of planned refueling and maintenance outages for SLR activities is not yet reflected in the NERC Brochures, including in the most recent Brochure for the five-year period from 2017 to 2021 for comparable pressurized water reactor units.

Surry Power Station was the third nuclear station in the industry to receive approval for SLR in 2021. The NRC has issued three SLR renewed licenses and there are five applications currently under review with the NRC, including North Anna Power Station's application. In addition, three applications will be submitted to the NRC in 2024, and one additional application in 2025 and 2026, respectively.[1] Overtime, as more nuclear stations implement SLR, the

[1] *See* U.S. Nuclear Regulatory Commission Status of Subsequent License Renewal Applications, *available at* https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html (last visited Aug. 15, 2023).

effect of SLR-related activities may be reflected in the nuclear industry capacity factor reported in the NERC Brochure.

Q. What is the Company's approach to outage extensions and forced outages?

A. The Company evaluates outage scope changes or extensions and forced outage scopes based on the commensurate impact of the emerging issue. We may add activities to the schedule that were not anticipated in the original outage plan considering potential cost, system health or operations, radiation exposure, and regulatory obligations.

In the event of a forced outage the Company's goal is to recover the unit in an expeditious manner. Successful forced outage implementation includes identifying the optimum scope of work to be performed. The Company limits core activities to those required to correct the cause of the forced outage and safely restart the unit. Other activities may be added if they contribute to reliable operation and do not extend the expected duration of the forced outage. The Company frequently reviews the scope of the forced outage during the forced outage period to determine required activities to correct the problem that caused the forced outage, any activities required by regulatory requirements prior to restart, and activities that prevent the unit from achieving rated output.

Q. What analysis of forced outages and outage extensions does the Company perform?

A. Nuclear power plants are required to have a corrective action program, and as part of this program causal analyses may be performed. The NRC mandates through the Code of Federal Regulations ("CFR") 10 C.F.R. Part 50, Appendix B Criterion XVI 'Corrective Action' that the nuclear licensee will establish measures "…to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management." The Company's corrective action program establishes the actions to be taken to assure that conditions adverse to quality are promptly identified and corrected. The Company's corrective action procedure identifies what type of cause analysis, if any, is required for conditions adverse to quality.

Additionally, the Company performs reviews of forced outages and outage extensions and applies the lessons learned from such reviews going forward. The Company strives to improve outage execution as part of the continuous improvement culture that the Company endeavors to maintain. In addition, the Nuclear Fleet performs outage and planning internal self-assessments as well as benchmarking of how other nuclear utilities perform refueling and maintenance outages to identify industry best practices.

Q. Are such analyses intended to assess or determine the prudence or reasonableness of a particular action or decision?

A. No. These analyses are not intended to determine the prudence or reasonableness of a particular action or decision during an outage. The Corrective Action Program causal analyses identify and establish steps to correct conditions adverse to quality. Outage review captures outage improvement items to ensure continuous improvement and excellence.

Q. Did the Company complete any refueling outages for the Nuclear Fleet during the Test Period?

A. Yes. The Company completed three refueling outages during the Test Period. In addition to refueling, planned maintenance and inspection activities were completed during these planned outages to ensure continued plant reliability.

North Anna Power Station Unit 1 began a refueling outage on September 20, 2022, and returned online October 26, 2022. This outage lasted 36.7 days compared to a scheduled allocation of 38 days. Major activities included inspection of the low-pressure turbine rotor, main generator tuning weight repair, repair of the containment air recirculating fan motor failure, and control rod drive mechanism cable repair.

Surry Power Station Unit 1 began a refueling outage on October 30, 2022, and returned online December 17, 2022. This outage lasted 48 days compared to a scheduled allocation of 44 days. Major projects completed included a reactor vessel flow modification, a residual heat removal heat exchanger replacement for SLR, and inspection of the reactor vessel internal components including baffle former bolts.

Surry Power Station Unit 2 began a refueling outage on April 23, 2023, and returned online June 8, 2023. This outage lasted 46.8 days compared to a scheduled duration of 46 days. Comparable major projects were completed as performed in the previous fall for Surry Power Station Unit 1.

These refueling and maintenance outages for Surry Power Station Unit 1 and Unit 2 had a planned duration to accommodate both a large modification to the reactor vessel internals and inspection of the reactor vessel internals that is required on a periodicity of every 10 years. This caused an incremental increase in the planned outage durations of approximately seven days each. Both outage activities required the removal of the upper and lower reactor vessel internals to allow access to the lower core barrel. This work was completed successfully and with no significant issues.

When the incremental implementation days for these two activities are accounted for with respect to the two most recent refueling and maintenance outages at Surry Power Station, the average net capacity factor for the two-year period from July 1, 2021 to June 30, 2023 would have been over 93.42%. This would meet the criteria for Commission Rule R8-55(k).

Q. Other than refueling, what outages occurred at the Company's Nuclear Facilities during the Test Period?

A. North Anna Power Station Unit 2 had a planned maintenance outage from August 13, 2022, to August 27, 2022, for replacement of a degrading "C" reactor coolant pump seal. The planned maintenance outage duration was 13.10 days. Unexpected fluctuations in the "C" reactor coolant pump seal stage delta pressures first occurred on April 22, 2022, due to premature failure of vendor-supplied equipment. The "C" reactor coolant pump continued to degrade to the point where a planned maintenance outage was required to replace the seal.

North Anna Power Station Unit 2 had a forced outage from August 27, 2022, to September 18, 2022, to address a failure of the 500 kV high voltage bushing of the "A" main transformer due to a vendor manufacturing defect. The forced outage duration was 22.05 days. Major work included replacement of the "A" main transformer and replacement of the high-side bushings on the "B" and "C" main transformers. A spare transformer was onsite at North Anna Power Station to replace the "A" main transformer, which shortened the lead time that would have been required had no ready replacement been available.

The manufacturing defect of the 500 kV high voltage bushing could not have been foreseen and prevented. When the incremental forced outage days are accounted for, the average net capacity factor for the two-year period from July 1, 2021 to June 30, 2023 would have been over 93.10%.

Surry Power Station Unit 2 experienced a forced outage with a controlled normal shut down from 30% power on June 10, 2023, and returned to service on June 14, 2023. The forced outage duration was 4.65 days. Operations staff observed rising pressurizer relief tank pressure due to leak-by of the "B" pressurizer safety valve. Major work during the forced outage included replacement of the "B" pressurizer safety valve and maintenance on the main steam line non-return valve. The causal analysis is in progress.

Q. Is there anything you would like to say in closing?

A. Yes. The Company's Nuclear Fleet has a history of strong operational performance that has historically exceeded industry averages. The full context of the Company's reasonable and prudent management of the outages that occurred at the Nuclear Fleet during the test year that I have discussed in my testimony demonstrates the Company's continued commitment to achieving high performance from the Nuclear Fleet while maintaining safety and reliability.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
JAMES HOLLOWAY

I have a Bachelor of Science degree in electrical engineering from North Carolina Agricultural and Technical State University and received a shift technical advisor certificate in 2004 and senior reactor operator certificate in 2007 from Surry Power Station. I joined the Company in 2001 as a design engineer at the Surry Power Station and then joined the Operations department to become a shift technical advisor. I became supervisor of Engineering Coordination in 2009 and subsequently held a series of supervisory positions in Nuclear Engineering at Surry Power Station. In January 2018 I became the Manager Site Engineering and transferred to Manager Nuclear Site Services in September 2018 at Surry Power Station. In 2020 I became the Director Nuclear Engineering at Surry Power Station and held that position until August 2022 when I assumed my current role.

DIRECT TESTIMONY OF
ALAN J. MOORE
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 675

Q. Please state your name, business address, and position of employment.

A. My name is Alan J. Moore, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am a Supervisor of Accounting for the Dominion Energy Virginia and Contracted Assets operating segments of Dominion Energy, Inc., which includes responsibility for Virginia Electric & Power Company, which operates in North Carolina as Dominion Energy North Carolina (the "Company"). My responsibilities include overseeing personnel responsible for recording the Company's actual fuel and purchased power expenses, as well as any under-/over-recovery of such expenses through the fuel deferral mechanism, operation and maintenance accounting activities, reserve analysis and joint owner billings. A statement of my background and qualifications is attached as Appendix A.

Q. Mr. Moore, what is the purpose of your testimony in this proceeding?

A. My testimony presents: 1) the Company's actual system fuel expenses for the 12 months ended June 30, 2023 ("Test Period"); 2) the Company's North Carolina recovery experience as of June 30, 2023; and 3) the accounting treatment for non-utility generators ("NUGs").

Q. In the course of your testimony will you introduce any exhibits?

A. Yes. Company Exhibit AJM-1 has been prepared under my direction and supervision and is accurate and complete to the best of my knowledge and belief. Company Exhibit AJM-1 consists of the following five schedules, as prescribed by North Carolina Utilities Commission ("Commission") Rule R8-55:

Schedule 1: Actual System Fuel and Purchased Power Expenses

Schedule 2: North Carolina Recovery Experience

Schedule 3: Actual Kilowatt-hour Sales

Schedule 4: Actual Fuel-Related Revenues

Schedule 5: Inventories of Fuel Burned

Q. Please provide the Company's actual fuel expenses incurred for the Test Period and the Company's North Carolina recovery position as of June 30, 2023.

A. Based on the North Carolina jurisdictional fuel factor methodology approved by the Commission, the actual system fuel expenses incurred by the Company during the Test Period totaled $3,116,591,080. The Company was in a fuel cost under-recovery position of $38,607,430 on a North Carolina jurisdictional basis as of June 30, 2023. Details regarding fuel expenses and the calculation of this under-recovery position, also referred to as the Experience Modification Factor ("EMF"), are provided in Company Exhibit AJM-1 and are discussed later in my testimony.

Q. Were any adjustments to the North Carolina June 30, 2023 recovery position necessary to calculate the EMF?

A. Yes. The stipulated EMF included in the Docket No. E-22, Sub 644 Final Order addressed an under-recovery of $66,729,993. A portion of that under-recovery balance, in the amount of $21,029,046, was due to the under-recoveries in the months of July and August 2022. Since these months overlap with the current filing Test Period, the under-recovery from these two months must be removed from the North Carolina June 30, 2023, recovery position before determining the EMF. The resulting adjusted EMF is an under-recovery of $17,578,384.

Q. How did the Company account for NUG energy costs?

A. The Company does not currently have any dispatchable NUGs. If there were contracts with dispatchable NUGs in the future, the Company would include in the EMF calculation the actual fuel costs provided by those dispatchable NUGs. For dispatchable NUGs that do not provide actual fuel costs, the Company would include 71% of the energy costs in the EMF calculation. Additionally, if a dispatchable NUG provides market-based energy rather than dispatching its facility, the Company would include 71% of the reasonable and prudent energy costs for such market-based energy in the EMF calculation as approved by the Commission in the Company's 2022 fuel factor proceeding, Docket No. E-22, Sub 644.

Q. Please provide an explanation of the five schedules presented in Company Exhibit AJM-1.

A. Schedule 1, Column 1 presents the system fuel and purchased power expenses incurred by the Company during the Test Period totaling $3,511,909,809. Of that amount, $3,116,591,080 was included in the EMF calculation based on the North Carolina jurisdictional fuel factor methodology approved by the Commission, as shown by month in Column 2.

Q. Please explain the adjustments that cause the amounts in Schedule 1, Column 1 to differ from those in Schedule 1, Column 2.

A. The following adjustments are necessary to comply with Commission Rule R8-55 and its orders pertaining to fuel expenses.

1. <u>Nuclear (Page 1 of Schedule 1)</u>

   Column 2 excludes costs related to the interim storage of spent nuclear fuel.

2. <u>Purchased Power (Page 2 of Schedule 1)</u>

   Column 2 excludes PJM capacity costs, the non-fuel portion of purchases from PJM and any non-fuel NUG expenses not approved for recovery through the fuel factor.

Q. Schedule 2 shows that the EMF calculation resulted in an under-recovery of $17,578,384. Please provide further explanation of this schedule.

A. Schedule 2 presents the North Carolina jurisdictional recovery experience by month for the Test Period. Schedule 2 is presented in three parts. Part I shows the total North Carolina system fuel and purchased power costs excluding the system allowance for funds used during construction ("AFUDC"). Part II shows the North Carolina jurisdictional fuel and purchased power costs including credit adjustments for the fuel cost from non-requirements sales and PJM off-system sales and other fuel-related adjustments. Part III presents, by month, the North Carolina jurisdictional fuel revenues and the North Carolina jurisdictional monthly and cumulative recovery experience, as well as the total adjustment for the months of July and August 2022, which was detailed previously in my testimony.

Q. What were the total fuel costs and fuel revenues for North Carolina jurisdictional customers for the Test Period?

A. The fuel costs allocated to North Carolina jurisdictional customers totaled $137,441,662. The Company received fuel revenues totaling $98,834,232. The difference between the fuel costs and the fuel revenues resulted in an under-recovery of $38,607,430 for the Test Period.

Q. Please describe the information contained in Schedules 3 - 5 presented in Company Exhibit AJM-1.

A. Schedule 3 provides the actual kilowatt-hour sales at a system level and at the North Carolina jurisdictional customer level for the Test Period. Schedule 4 provides actual fuel revenues recorded for the Test Period. For the current proceeding, Schedule 4 also includes Rider B revenues for July 2023, which is outside of the current test year, as support for Company Exhibit TPS-1, Schedule 6, filed by Company Witness Timothy P. Stuller. Column 1 of Schedule 4 provides the system fuel revenue, Column 2 provides the revenue received from North Carolina jurisdictional customers for the current fuel Test Period, and Column 3 provides the revenue received from North Carolina jurisdictional customers for Rider B. Schedule 5 provides inventory values of fuels burned in the production of electricity. Inventory values are recorded on the books of Virginia Electric and Power Company and its subsidiary, Virginia Power Services Energy Corp, Inc.

Q. Mr. Moore, does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

**BACKGROUND AND QUALIFICATIONS
OF
ALAN J. MOORE, CPA**

Alan J. Moore graduated from Longwood University in 2007 with a Bachelor's of Science degree in Business Administration with a concentration in accounting, and also received his Masters of Business Administation from Longwood University in 2015. Mr. Moore received his Certified Public Accountant license in 2019. He has worked at Dominion Energy since 2007 and has held prior roles in Internal Audit, Regulatory Accounting, and DEV accounting departments. He transitioned into his current role in 2023. His current responsibilities include overseeing personnel responsible for the Company's regulated fuel and operation and maintenance accounting activities, purchased power expenses, deferred fuel mechanism, reserve analysis and joint owner billings.

Mr. Moore has previously presented testimony before the North Carolina Utilities Commission.

Dominion Energy North Carolina
Actual System Fuel and Purchased Power Expenses
July 2022 - June 2023

	System Expenses As Booked (1)	North Carolina System Expenses As Booked (2)
Steam Generation Fuel Cost		
July 2022	$ 38,382,591	$ 38,382,591
August	29,578,139	29,578,139
September	12,491,598	12,491,598
October	4,542,456	4,542,456
November	12,554,208	12,554,208
December	37,838,113	37,838,113
January 2023	19,014,873	19,014,873
February	29,340,406	29,340,406
March	26,595,464	26,595,464
April	19,187,132	19,187,132
May	24,338,523	24,338,523
June	22,717,262	22,717,262
FERC Account 501 - Steam Fuel Cost	$ 276,580,766	$ 276,580,766
Nuclear Generation Fuel Cost		
July 2022	$ 15,255,444	$ 14,488,002
August	13,130,534	12,440,636
September	10,847,207	10,760,603
October	11,282,976	11,169,486
November	10,883,087	10,852,139
December	13,023,885	12,853,467
January 2023	14,715,078	14,608,167
February	13,939,644	13,372,099
March	17,122,739	16,999,529
April	13,267,775	12,584,990
May	10,891,965	10,799,643
June	17,235,670	12,778,892
FERC Account 518 - Nuclear Fuel Cost	$ 161,596,005	$ 153,707,653

Dominion Energy North Carolina
Actual System Fuel and Purchased Power Expenses
July 2022 - June 2023

	System Expenses As Booked (1)	North Carolina System Expenses As Booked (2)
Other Generation Fuel Cost		
July 2022	$ 220,387,215	$ 220,387,215
August	255,169,557	255,169,557
September	163,505,871	163,505,871
October	108,428,320	108,428,320
November	106,179,347	106,179,347
December	240,211,589	240,211,589
January 2023	138,421,075	138,421,075
February	112,981,922	112,981,922
March	79,689,860	79,689,860
April	44,429,793	44,429,793
May	54,960,265	54,960,265
June	68,004,119	68,004,119
FERC Account 547 - Other Fuel Cost	$ 1,592,368,933	$ 1,592,368,933
Total Cost of Fuel Used in Current Generation	$ 2,030,545,703	$ 2,022,657,351
Purchased Power		
July 2022	146,610,249	$ 109,124,518
August	233,435,160	167,463,678
September	226,127,614	171,637,167
October	129,293,461	96,989,900
November	155,775,624	115,154,744
December	187,659,944	134,611,930
January 2023	62,239,291	48,188,122
February	43,423,702	33,457,160
March	46,713,757	34,998,986
April	112,172,799	83,173,593
May	95,777,335	70,566,281
June	42,135,170	28,567,648
FERC Account 555 - Purchased Power Cost	$ 1,481,364,106	$ 1,093,933,729

Dominion Energy North Carolina
Actual System Fuel and Purchased Power Expenses
July 2022 - June 2023

	System Expenses As Booked (1)	North Carolina System Expenses As Booked (2)
Total Fuel and Purchased Power Cost		
July 2022	$ 420,635,500	$ 382,382,326
August	531,313,391	464,652,010
September	412,972,289	358,395,239
October	253,547,213	221,130,163
November	285,392,266	244,740,437
December	478,733,531	425,515,099
January 2023	234,390,317	220,232,237
February	199,685,675	189,151,588
March	170,121,820	158,283,840
April	189,057,499	159,375,508
May	185,968,088	160,664,712
June	150,092,222	132,067,922
Total Fuel and Purchased Power Cost	$ 3,511,909,809	$ 3,116,591,080

Dominion Energy North Carolina
Docket No. E-22, Sub 675

Dominion Energy North Carolina
North Carolina Recovery Experience
Twelve Months Ended June 2023

PART I	July-22	August-22	September-22	October-22	November-22	December-22	January-23	February-23	March-23	April-23	May-23	June-23	Total
FERC Account 501 - Steam Fuel Cost	$ 38,382,591	$ 29,578,139	$ 12,491,598	$ 4,542,456	$ 12,554,208	$ 37,838,113	$ 19,014,873	$ 29,340,406	$ 26,595,464	$ 19,187,132	$ 24,338,523	$ 22,717,262	$ 276,580,766
FERC Account 518 - Nuclear Fuel Cost	$ 14,488,002	$ 12,440,636	$ 10,760,603	$ 11,169,486	$ 10,852,139	$ 12,853,467	$ 14,608,167	$ 13,372,099	$ 16,999,529	$ 12,584,990	$ 10,799,643	$ 12,778,892	$ 153,707,653
FERC Account 547 - Other Fuel Cost	$ 220,387,215	$ 255,169,557	$ 163,505,871	$ 108,428,320	$ 106,179,347	$ 240,211,589	$ 138,421,075	$ 112,981,922	$ 79,689,860	$ 44,429,793	$ 54,960,265	$ 68,004,119	$ 1,592,368,933
FERC Account 555 - Purchased Power Cost	$ 109,124,518	$ 167,463,678	$ 171,637,167	$ 96,989,900	$ 115,154,744	$ 134,611,930	$ 48,188,122	$ 33,457,160	$ 34,998,986	$ 83,173,593	$ 70,566,281	$ 28,567,648	$ 1,093,933,729
Total NC System Fuel and Purchased Power Cost	$ 382,382,326	$ 464,652,010	$ 358,395,239	$ 221,130,163	$ 244,740,437	$ 425,515,099	$ 220,232,237	$ 189,151,588	$ 158,283,840	$ 159,375,508	$ 160,664,712	$ 132,067,922	$ 3,116,591,080
Exclude System AFUDC	(30,607)	(24,522)	(20,676)	(24,589)	(30,948)	(35,895)	(40,140)	(36,598)	(40,376)	(36,042)	(32,622)	(33,794)	(386,809)
Total NC System Fuel and Purchased Power Cost w/o AFUDC	$ 382,351,719	$ 464,627,488	$ 358,374,562	$ 221,105,573	$ 244,709,489	$ 425,479,204	$ 220,192,097	$ 189,114,990	$ 158,243,464	$ 159,339,466	$ 160,632,090	$ 132,034,128	$ 3,116,204,271
PART II													
NC Jurisdictional Fuel and Purchased Power Cost w/o AFUDC	$ 19,693,824	$ 19,696,959	$ 16,326,137	$ 9,758,862	$ 10,293,059	$ 19,162,788	$ 7,952,303	$ 8,542,427	$ 6,926,247	$ 8,101,544	$ 3,644,373	$ 7,316,767	$ 137,415,288
Credit for the fuel cost from Non-Requirement Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Credit for the fuel cost from PJM Off-system Sales	$ (102,117)	$ 9,384	$ -	$ (990)	$ -	$ (198,073)	$ (26,581)	$ (13,914)	$ (18,294)	$ 746	$ -	$ (3,876)	(353,717)
RGGI Related Emissions	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Fuel Related Adjustments [1]	30,084	24,096	20,317	24,161	30,410	35,271	39,441	35,961	39,673	35,415	32,055	33,206	380,091
Adjusted NC Jurisdiction Fuel and Purchased Power Cost	$ 19,621,791	$ 19,730,438	$ 16,346,453	$ 9,782,033	$ 10,323,469	$ 18,999,986	$ 7,965,163	$ 8,564,474	$ 6,947,626	$ 8,137,704	$ 3,676,428	$ 7,346,097	$ 137,441,662
PART III													
Adjusted NC Jurisdiction Fuel and Purchased Power Cost	$ 19,621,791	$ 19,730,438	$ 16,346,453	$ 9,782,033	$ 10,323,469	$ 18,999,986	$ 7,965,163	$ 8,564,474	$ 6,947,626	$ 8,137,704	$ 3,676,428	$ 7,346,097	$ 137,441,662
NC Jurisdictional Revenue	(10,294,897)	(7,387,173)	(7,067,573)	(6,173,517)	(6,606,004)	(7,871,233)	(5,608,381)	(10,073,784)	(10,198,876)	(10,244,072)	(4,717,126)	(12,591,596)	(98,834,232)
(Over)/Under Recovery	$ 9,326,893	$ 12,343,265	$ 9,278,880	$ 3,608,516	$ 3,717,465	$ 11,128,753	$ 2,356,782	$ (1,509,310)	$ (3,251,249)	$ (2,106,368)	$ (1,040,698)	$ (5,245,499)	$ 38,607,430
Cumulative (Over)/Under Recovery	$ 9,326,893	$ 21,670,158	$ 30,949,039	$ 34,557,555	$ 38,275,020	$ 49,403,772	$ 51,760,555	$ 50,251,245	$ 46,999,995	$ 44,893,627	$ 43,852,929	$ 38,607,430	

[1] Includes jurisdictional AFUDC and AFUDC tax credits.
[2] The adjustment removes the amount of the test period Experience Modification Factor (EMF) that is already being recovered, or will be recovered, as part of the stipulated EMF per E-22, Sub 644 Final Order

Dominion Energy North Carolina
Actual Kilowatt-hour (kWh) Sales
Twelve Months Ended June 2023

(In Thousands)

	System kWh Sales* (1)	North Carolina Retail kWh Sales* (2)
July 2022	9,368,723	482,517
August	8,101,338	343,422
September	7,244,217	343,422
October	6,550,567	289,088
November	7,330,711	308,308
December	8,180,026	368,382
January 2023	7,177,326	259,164
February	6,990,775	315,716
March	7,620,549	333,463
April	6,564,424	333,690
May	6,703,445	152,055
June	7,455,203	413,030
Total kWh Sales	89,287,302	3,942,256

*Including unbilled kWh sales.

Dominion Energy North Carolina
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Company Exhibit AJM-1
Schedule 4

Dominion Energy North Carolina
Actual Fuel Related Revenues
Twelve Months Ended June 2023

	System Fuel Related Revenues As Booked*	North Carolina Retail Fuel Factor Related Revenues*	
		Current Period	EMF Rider B
	(1)	(2)	(3)
July 2022	$317,862,594	$ 10,294,897	908,680
August	284,367,112	7,387,173	652,058
September	289,101,138	7,067,573	623,823
October	251,107,428	6,173,517	544,914
November	269,340,509	6,606,004	583,080
December	295,281,473	7,871,233	694,759
January 2023	274,108,586	5,608,381	495,047
February	251,764,951	10,073,784	1,625,329
March	270,382,799	10,198,876	1,582,337
April	224,229,667	10,244,072	1,589,261
May	235,044,913	4,717,126	731,914
June	261,620,602	12,591,596	1,953,563
July (1)			1,832,834
Total Fuel Related Revenues	$ 3,224,211,774	$ 98,834,232	$ 13,817,598

*Including unbilled kWh revenues.
(1) July Rider B revenues included as support for TPS Schedule 4

Dominion Energy North Carolina
Docket No. E-22, Sub 675

Company Exhibit AJM-1
Schedule 5

Dominion Energy North Carolina
Inventories of Fuel Burned
As of June 30, 2023

Fuel	Inventory Measure		Inventory Volume	Inventory Value
(1)	(2)		(3)	(4)
Coal [b]	Tons	Coal Rec	830,361	$ 139,882,622
Wood [b]	Tons	Wood & Jet Fuel Rec	74,671	2,625,903
Light Oil [a]	Gallons	Oil Rec	61,710,028	157,371,891
Heavy Oil [a]	Barrels	Oil Rec	405,521	4,354,476
Jet Fuel [a]	Gallons	Wood & Jet Fuel Rec	91,352	239,074
Natural Gas [a]	Dth	Power Gen. Summary	1,827,069	6,412,692
Nuclear Fuel Stock [b]	N/A			518,961,521
Total				$ 829,848,179

(a) Inventories are held by Virginia Power Services Energy Corp, Inc.
(b) Inventories are held by Virginia Electric & Power Company.

DIRECT TESTIMONY OF
DALE E. HINSON
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 675

Q. Please state your name, business address, and position of employment.

A. My name is Dale E. Hinson, and my business address is 600 Canal Street, Richmond, Virginia 23219. I am the Director of Fuel Commodities and a member of the management team responsible for fossil fuel procurement for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina (the "Company"). The Dominion Energy Fuels Management team handles the procurement, scheduling, transportation, and inventory management for natural gas, coal, biomass, and oil consumed at the Company's power stations. A statement of my background and qualifications is attached as Appendix A.

Q. What is the purpose of your testimony in this proceeding?

A. I will discuss the Company's fossil fuel procurement practices, including any recent changes to those practices, for the delivery of fuels to the Company's fossil generation fleet during the test period of July 1, 2022 to June 30, 2023 ("Test Period"), in compliance with Commission Rule R8-55(e)(5).

Q. Are you sponsoring any exhibits?

A. Yes. Company Exhibits DEH-1 and DEH-2 were prepared under my direction and are accurate and complete to the best of my knowledge.

Company Exhibit DEH-1 Schedule 1 is the Dominion Energy North Carolina Summary Report of Fuel Transactions with Affiliates during the Test Period. Company Exhibit DEH-2 is the Company's Fuel Procurement Strategy Report, discussed further below in my testimony.

SECTION I
FUEL COMMODITY MARKETS AND PROCUREMENT STRATEGIES

Q. Please discuss the trends that affected fuel commodity markets during the period of July 2022 through June 2023.

A. Price volatility has been and will likely continue to be prevalent across the natural gas, coal, oil, and biomass fuel commodities. For natural gas, we witnessed an initial commodity price increase followed by a dramatic price decline. The initial natural gas price increase was largely caused by concerns, both domestically and in Europe, with sufficient fuel storage inventories to meet anticipated winter 2022/23 demand. Domestically, the start of the summer 2022 injection season witnessed storage inventories below five-year average inventory levels and by mid-summer, there were industry concerns that storage inventories would not be sufficient to overcome the pre-injection season deficit. These concerns were particularly heightened in Europe, as summer 2022 marked the beginning of Russian natural gas import reductions, in response to certain European nations' opposition to the war in Ukraine. As a result, liquid natural gas ("LNG") prices, both in Europe and Asia, increased to attract replacement natural gas supplies from the international supply market (including the United States). In response, domestic natural gas exports were maximized to capture high priced (compared to domestic natural gas prices) international markets.

However, natural gas commodity price trends reversed once winter 2022/23 demand "projections" started to become reality. Lower natural gas prices resulted from some of the following: lower regional consumption, easing international LNG demand (and associated price decreases), continued strength in domestic natural gas production, and a healthy domestic natural gas storage inventory at the start of the 2023 injection season.

Q. Please continue.

A. Closer to home, North Carolina experienced temperatures for winter 2022/23 approximately 13% warmer than winter 2021/22 and 24% warmer than the 30-year normal. While the Mid-Atlantic region recalls the unseasonably cold Christmas 2022 weekend (Winter Storm Elliott), December 2022 averaged to be only 5% colder than the 30-year normal, in North Carolina. The remaining months of winter 2022/23 never materialized as January, February and March were 28% warmer than the similar period in 2022 and 34% warmer than the 30-year average. Furthermore, domestic natural gas storage inventories have remained relatively high. As we began the 2023 injection season, March 2023 ending inventories were 21% above the five-year inventory level at 1.85 trillion cubic feet. This trend continues into early June 2023, as storage inventory is now at 2.55 trillion cubic feet, or approximately 16% higher than the five-year average inventory and 28% higher than for the same period, last year.

Q. How do Europe and Asia continue to affect certain fuel commodity price trends?

A. Both European and Asian LNG markets continue to affect natural gas pricing in the United States. As of June 2023, roughly 17% of domestic natural gas production (approximately 18 Bcf/day) was exported to international markets. The vast majority of these exports were in the form of LNG, with ultimate markets in Europe and Asia. Consequently, as international LNG markets reflect considerably higher prices, compared to domestic natural gas markets, producers will seek to maximize LNG exports and commit supplies that would otherwise serve domestic demand.

A similar supply and price dynamic was experienced with domestic coal and oil production and associated prices. Domestic coal prices also increased during summer 2022, as Europe announced bans on Russian coal exports. However, as Europe attempted to renounce ties to Russian coal, it looked largely to the United States as a replacement source. As a result, summer 2022 European coal prices increased to more than $350/ton while domestic CAPP coal prices reached as high as $200/ton. However, like natural gas, domestic coal prices have declined (currently in the $70/ton range) as winter 2022/23 fueling concerns eased, both domestically and in Europe, coupled with steady domestic coal production. Domestic oil markets have and continue to be affected by international demand and associated prices. Lastly, after a summer 2022 price increase, similar to what was seen with natural gas and coal, domestic oil prices have fallen back to 2021 price levels. The 2023 year-to-date average West Texas Intermediate ("WTI") price is at $76/barrel, representing a 26% decrease compared to the same period last year.

Q. Has the Company changed its fuel procurement practices?

A. No. The Company continues to follow the same procurement policy as it has in the past in accordance with the Company's Fuel Procurement Practices Report ("Dominion Fuel Policy"), a copy of which was filed with the Commission on December 30, 2013, in Docket No. E-100, Sub 47A. The Dominion Fuel Policy addresses the physical procurement of fossil and nuclear fuels. Lastly, per Commission Rule R8-52(a), the Company intends to file its 10-year update to the Dominion Fuel Policy by December 31, 2023.

Q. Has the Company changed its fuel hedging program?

A. No. The Company continues to follow its fuel hedging program discussed in greater detail in the Fuel Procurement Strategy Report filed most recently with the Virginia State Corporation Commission ("VSCC") on January 31, 2023, in VSCC Case No. PUR-2022-00064 (the "Report"). Please see Company Exhibit DEH-2 for the Report. The Company believes its comprehensive approach to hedging (*e.g.*, price hedging, diverse fuel supply access, and diverse (including coal, oil, biomass, and nuclear) generation portfolio) has and continues to have a material mitigating effect on the Company's fuel cost volatility.

Q. Mr. Hinson, in addition to its hedging program, how else does the Company mitigate fuel cost expenses?

A. The Company deploys various fuel cost mitigation activities while providing safe and reliable electricity for its customers. These activities include, but are not limited to:

- natural gas seasonal firm transportation contract changes ensuring that least cost supplies reach the most efficient generation units and acquisition of incremental pipeline capacity (short-term release or longer-term firm contracts) to provide greater access to competitively priced fuel supply and greater fueling flexibility in response to PJM Interconnection, LLC ("PJM") requirements;
- natural gas daily/monthly/seasonal monetization efforts (*e.g.*, AMA arrangements, short-term capacity releases, and natural gas delivered sales) for select pipeline contract segments with all the resulting revenues returned to the ratepayers through fuel cost offsets;
- maintaining offsite biomass inventory;
- coal rail and trucking service contracting paired with a layering approach for coal supply contracts; and
- diversifying oil inventory storage and replenishment sources.

Q. You mention both short-term and long-term pipeline capacity acquisitions to provide greater access to competitively priced natural gas supplies and greater fueling flexibility. Why are these important options to consider?

A. The Company's gas-fired generation fleet is in the Mid-Atlantic region, a region characterized by pipeline constraints and high price volatility. This is primarily due to this region's continued high demand for natural gas without adequate supply offsets, from pipeline transportation capacity with access to incremental natural gas supply. While incremental firm transportation continues to be promised, the existing natural gas demand and supply imbalance remains. The lack of intra-day natural gas supply experienced in this region during Winter Storm Elliott – specifically over the four-day Christmas holiday weekend – was the latest example of this natural gas fuel demand and supply imbalance.

Q. What were some of the Company's observations during Winter Storm Elliott?

A. From a natural gas generator's perspective operating in the Company's generation region, Winter Storm Elliott illustrated the importance of alternate fuel supplies (and associated firm access), both onsite and offsite. Once natural gas day-ahead trading was completed, intra-day gas supply opportunities were inadequate, as several factors (weather and non-weather related) affected supply availability and deliverability. Consequently, gas generators with an over-reliance on intra-day gas supply markets struggled to provide incremental generation.

Q. What long-term pipeline or supply options is the Company considering?

A. As discussed in its Fuel Procurement Strategy Report, the Company continuously reviews its natural gas supply and pipeline contract portfolio with optimal and cost-effective fuel deliverability and fueling flexibility in mind to meet PJM generation requirements. The need for these ongoing efforts was further supported by certain natural gas market observations from Winter Storm Elliott. Consequently, the Company recently executed agreements that significantly improve fueling capabilities and continues to pursue incremental opportunities for firm pipeline transportation (including storage), natural gas peaking services, and onsite fueling (LNG and/or oil). These potential service options would further enhance the Company's existing pipeline capacity portfolio. Lastly, given current pipeline construction and regulatory uncertainties associated with new natural gas pipeline builds, natural gas peaking services or on-site LNG and/or oil capabilities can be effective options to place specified amounts of fuel at specified generation station locations to help serve peak electric generation demand periods and/or to provide generation flexibility for PJM.

SECTION II
NATURAL GAS PROCUREMENT

Q. Please discuss the Company's gas procurement practices.

A. The Company maintains a disciplined natural gas procurement plan to ensure a reliable supply of natural gas at competitive prices. Through periodic solicitations and the open market, the Company serves its natural gas-fired fleet using a combination of day-ahead, monthly, seasonal, and multiyear physical gas supply purchases.

In addition to managing its natural gas supply portfolio, the Company evaluates its diverse portfolio of pipeline and storage contracts to determine the most reliable and economical delivered fuel options for each power station. This portfolio of natural gas transportation contracts provides access to multiple natural gas supply and trading points from the Marcellus shale region to the southeast region. Further, the Company actively participates in short-term, interstate pipeline capacity markets, buying capacity (when available) during times of need or selling capacity during low generation periods or power station outages.

Q. Were there any changes to the Company's natural gas-fired generation fleet during the Test Period?

A. No. There were no additions or retirements. Company-owned natural gas-fired generation accounted for as much as 58% and, on average, 51% of Company-owned electricity generation, during the Test Period.

SECTION III
COAL PROCUREMENT

Q. Please discuss the Company's coal procurement practices.

A. The Company employs a multiyear physical procurement plan to ensure a reliable supply of coal, delivered to its generating stations by truck or rail, at competitive prices. This is accomplished by procuring the Company's long-term coal requirements primarily through periodic solicitations and secondarily on the open market for short-term or spot needs. The effect of procuring both long- and short-term coal supplies provides a layering-in of contracts with staggered terms and blended prices. This ensures a reliable supply of fuel with limited exposure to potential dramatic market price swings. This blend of contract terms creates a diverse coal fuel portfolio and allows the Company to actively manage its fuel procurement strategy, contingency plans, and any risk of supplier non-performance. Furthermore, the generation flexibility afforded by the Company's coal generation fleet (complete with on-site fuel storage) is optimized to take advantage of fuel commodity price differentials to the benefit of its electric customers.

SECTION IV
<u>BIOMASS PROCUREMENT</u>

Q. Please discuss the Company's biomass procurement practices.

A. The Company has a varied procurement strategy for its biomass stations depending on the geographical region of the power station, while utilizing on- and off-site inventories to ensure adequate physical supply. Hopewell and Southampton Power Stations are served by multiple suppliers under both short and long-term agreements, enabling the Company to increase the reliability of its biomass supply by diversifying its supplier base. The Company purchases long-term fuel supply through one supplier at its Altavista Power Station. Procurement for the Company's biomass needs at its co-fired Virginia City

Hybrid Energy Center facility is also conducted via short and long-term contracts with various suppliers. All four biomass-consuming plants receive wood deliveries via truck.

SECTION V
OIL PROCUREMENT

Q. Please discuss the Company's oil procurement practices.

A. The Company purchases its No. 2 fuel oil and No. 6 fuel oil requirements on the spot market and optimizes its inventory, storage, and transportation to ensure reliable supply to its power generating facilities. Trucks, vessels, barges, and pipelines are employed to transport oil to the Company's stations and third-party storage locations, ensuring a reliable supply of oil and mitigating the price risk associated with potentially volatile prices for these products.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
DALE E. HINSON

Dale E. Hinson graduated from University of Missouri-Columbia in 1989 with a Bachelor of Science degree in Accounting and received a Master of Business Administration degree from Washington University in St. Louis-Olin Business School in 1997. He joined Dominion in 2006 as a Senior Energy Asset Trader and in 2011 became Manager of Power Asset Management, then in 2013, Manager – Gas Supply, then in 2022, Manager – Market Origination. In 2023, Mr. Hinson assumed his current role as Director of Fuel Commodities.

Prior to joining Dominion, Mr. Hinson worked most recently as a Senior Trader for LG&E and KU Energy LLC from 1997 to 2006. He has also held positions with Arch Coal as Director of Market Research and with Arthur Andersen & Co. as an Auditor.

Mr. Hinson has previously presented testimony before the North Carolina Utilities Commission and the State Corporation Commission of Virginia.

DOMINION ENERGY NORTH CAROLINA
SUMMARY REPORT OF FUEL TRANSACTIONS WITH AFFILIATES
FOR THE PERIOD JULY 2022 - JUNE 2023
(IN THOUSANDS $)

Dominion Energy North Carolina Receiving from Affiliate:

Docket No. E-22, Sub 675

VP Services Energy Corp., Inc.
Sale Of Natural Gas And Oil Inventory

	Month	Amount	
	July-22	$223,141	
	August-22	$257,837	
	September-22	$164,101	ACT
	October-22	$108,594	ACT
	November-22	$107,253	ACT
	December-22	$242,398	ACT
	January-23	$139,946	ACT
	February-23	$114,782	ACT
	March-23	$79,089	ACT
	April-23	$45,662	ACT
	May-23	$55,286	ACT
	June-23	$69,302	ACT
			ACT
Total Charged to FERC Account 151		$1,384,250	ACT

DOMINION ENERGY NORTH CAROLINA
SUMMARY REPORT OF FUEL TRANSACTIONS WITH AFFILIATES
FOR THE PERIOD JULY 2022 - JUNE 2023

Dominion Energy Fuel Services, Inc. and Virginia Power Services Energy Corp., Inc.
Natural Gas Transaction Summary

Docket No. E-22, Sub 675

	Volume			Dollars			WACOG		
	Purchase	Sale	Difference	Purchase	Sale	Difference	Purchase	Sale	Difference
7/1/2022	28,098,529	28,098,443	86	$ 182,805,205.97	$ 182,792,072.02	$ 13,133.95	$ 6.506	$ 6.505	0.000
8/1/2022	27,276,476	27,276,476	-	$ 211,951,603.68	$ 211,951,603.68	$ -	$ 7.770	$ 7.770	0.000
9/1/2022	21,377,954	21,381,789	(3,835)	$ 140,076,169.96	$ 140,096,432.18	$ (20,262.22)	$ 6.552	$ 6.552	0.000
10/1/2022	16,938,321	16,938,722	(401)	$ 77,215,596.42	$ 77,217,794.51	$ (2,198.09)	$ 4.559	$ 4.559	(0.000)
11/1/2022	16,498,488	16,498,488	-	$ 76,334,638.32	$ 76,333,392.82	$ 1,245.50	$ 4.627	$ 4.627	0.000
12/1/2022	22,089,284	22,090,133	(849)	$ 234,513,161.14	$ 234,516,152.92	$ (2,991.78)	$ 10.617	$ 10.616	0.000
1/1/2023	20,041,032	20,041,032	-	$ 93,992,937.46	$ 93,991,522.46	$ 1,415.00	$ 4.690	$ 4.690	0.000
2/1/2023	16,414,600	16,414,576	24	$ 84,435,695.25	$ 84,435,646.77	$ 48.48	$ 5.144	$ 5.144	(0.000)
3/1/2023	16,652,333	16,652,500	(167)	$ 49,319,981.49	$ 49,320,361.00	$ (379.51)	$ 2.962	$ 2.962	0.000
4/1/2023	17,473,494	17,473,558	(64)	$ 38,406,671.89	$ 38,406,792.21	$ (120.32)	$ 2.198	$ 2.198	0.000
5/1/2023	19,853,516	19,852,770	746	$ 40,604,398.42	$ 40,603,167.52	$ 1,230.90	$ 2.045	$ 2.045	(0.000)
6/1/2023	24,673,822	24,673,871	(49)	$ 47,355,872.64	$ 47,354,939.16	$ 933.48	$ 1.919	$ 1.919	0.000
Total	247,387,849	247,392,358	(4,509)	$ 1,277,011,932.64	$ 1,277,019,877.25	$ (7,944.61)			

DOMINION ENERGY NORTH CAROLINA
SUMMARY REPORT OF FUEL TRANSACTIONS WITH AFFILIATES
FOR THE PERIOD JULY 2022 - JUNE 2023

Dominion Energy North Carolina Power Receiving and Providing to Dominion Energy Fuel Services, Inc.:

Docket No. E-22, Sub 675

July 2022 - June 2023 Contracted Affiliated Fuel Transactions

There were no affiliate transactions of Fuel from July 2022 through June 2023.

McGuireWoods

McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, VA 23219-3916
Phone: 804.775.1000
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January 31, 2023

<u>BY ELECTRONIC DELIVERY</u>

Bernard Logan, Clerk
State Corporation Commission
Document Control Center
Tyler Building, First Floor
1300 East Main Street
Richmond, Virginia 23219

Application of Virginia Electric and Power Company to revise its fuel factor pursuant to Va. Code § 56-249.6
<u>Case No. PUR-2022-00064</u>

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-captioned proceeding, Virginia Electric and Power Company's *Fuel Procurement Strategy Report*.

Please do not hesitate to contact me if you have any questions in regard to this filing.

Sincerely,

<u>/s/ Elaine S. Ryan</u>

Elaine S. Ryan

Enclosures

cc: Lauren W. Biskie, Esq.
Lisa R. Crabtree, Esq.
Service List

Fuel Procurement Strategy

January 31, 2023

Virginia Electric and Power Company
d/b/a Dominion Energy Virginia

Case No: PUR-2022-00064

Contents

Introduction

Pursuant to the State Corporation Commission of Virginia's (the "Commission") directives in its August 21, 2015 Order Establishing 2015-2016 Fuel Factor in Case No. PUE-2015-00022,[1] Virginia Electric and Power Company (the "Company") submits this report ("Report") to describe its current fuel procurement strategy ("Fuel Procurement Strategy"), including an update of actual procurement and fuel price hedge details over the prior fuel year; an explanation of the Company's current risk management program, as well as any changes under consideration; and cost/benefit analyses of its financial and physical price hedge programs for each fuel type for at least the past five years.

This Report describes in detail the Company's historical and current fuel procurement and hedging practices. Section 1 describes the three types of risk management tools used by the Company. Section 2 presents the Company's current fuel procurement and hedging strategy. Section 3 details the Company's Fuel Procurement and Hedging Results for the current July 1, 2022 – June 30, 2023 Fuel Year (the "2022-2023 Fuel Year") and the last five fuel years (the 2017-2018 Fuel Year through the 2021-2022 Fuel Year). Section 4 addresses proposed changes to commodity procurement and hedging practices for the upcoming July 1, 2023 – June 30, 2024 Fuel Year (the "2023-2024 Fuel Year"). Section 5 discusses and analyzes the Company's Fuel Procurement and Hedging Programs, including a cost/benefit analysis and details of monetization transactions associated with its natural gas pipeline capacity portfolio, as directed by the Commission in Case No. PUR-2019-00070.[2] A glossary is included at the end of this Report to provide further explanation of terms used in this document.

[1] *Application of Virginia Electric and Power Company To revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia*, Case No. PUE-2015-00022, Order Establishing 2015-2016 Fuel Factor, 2015 S.C.C. Ann. Rept. 296-298 (Aug. 21, 2015).
[2] *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-2019-00070, Order Establishing 2019-2020 Fuel Factor at 9 (Aug. 15, 2019).

1 Risk Management Program

The Company's Fuel Procurement Strategy emphasizes reasonableness and prudency of costs consistent with Va. Code § 56-249.6, fuel diversity, security of supply, and a balanced approach to hedging. The Company utilizes the following types of risk management tools (as depicted in Figure 1 below) to protect customers from the impacts of significant fuel rate volatility: the availability of a diverse generation portfolio (Section 1.1 below); access to reliable fuel supply, inclusive of transportation and storage assets (procurement) (Section 1.2); and an effective commodity price hedging program incorporating physical and financial transactions (Section 1.3).

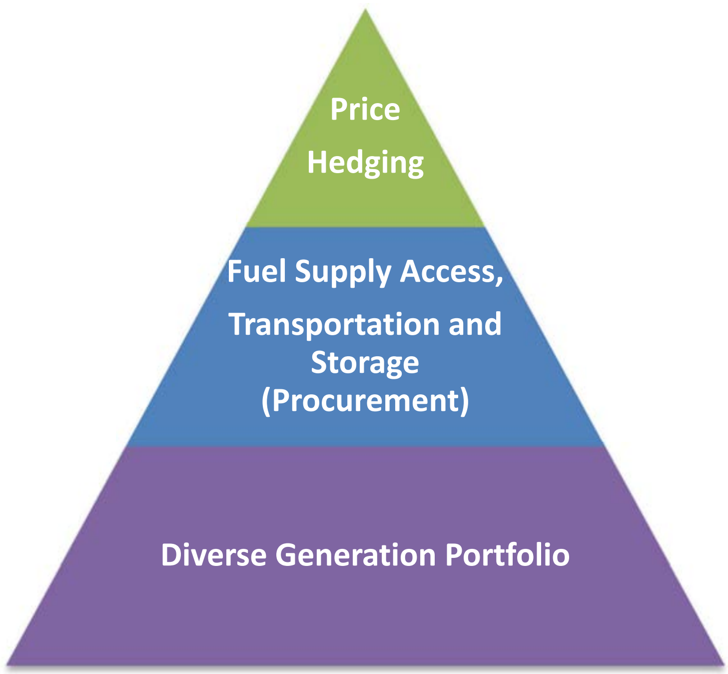

Figure 1 – Risk Management Tools

1.1 Diverse Generation Portfolio

The Company's diverse fleet of generation assets, which uses a variety of fuels and technologies, is a primary tool in protecting customers from the effects of commodity price volatility, commodity delivery disruptions, and other potential impacts related to changing regulatory requirements and real-time operating conditions.

The Company manages a diverse portfolio of assets covering a balanced mix of fuels as shown below in Figure 2. The Company's generation fleet includes units fueled by natural gas, coal, uranium, pumped storage, petroleum, and renewable sources (e.g., biomass, hydro, and solar). As commodity prices fluctuate, the Company's fleet is dispatched in the most economical manner, using and leveraging these different energy supply sources to respond to dynamic market conditions and reduce cost while maintaining reliability for the benefit of customers.

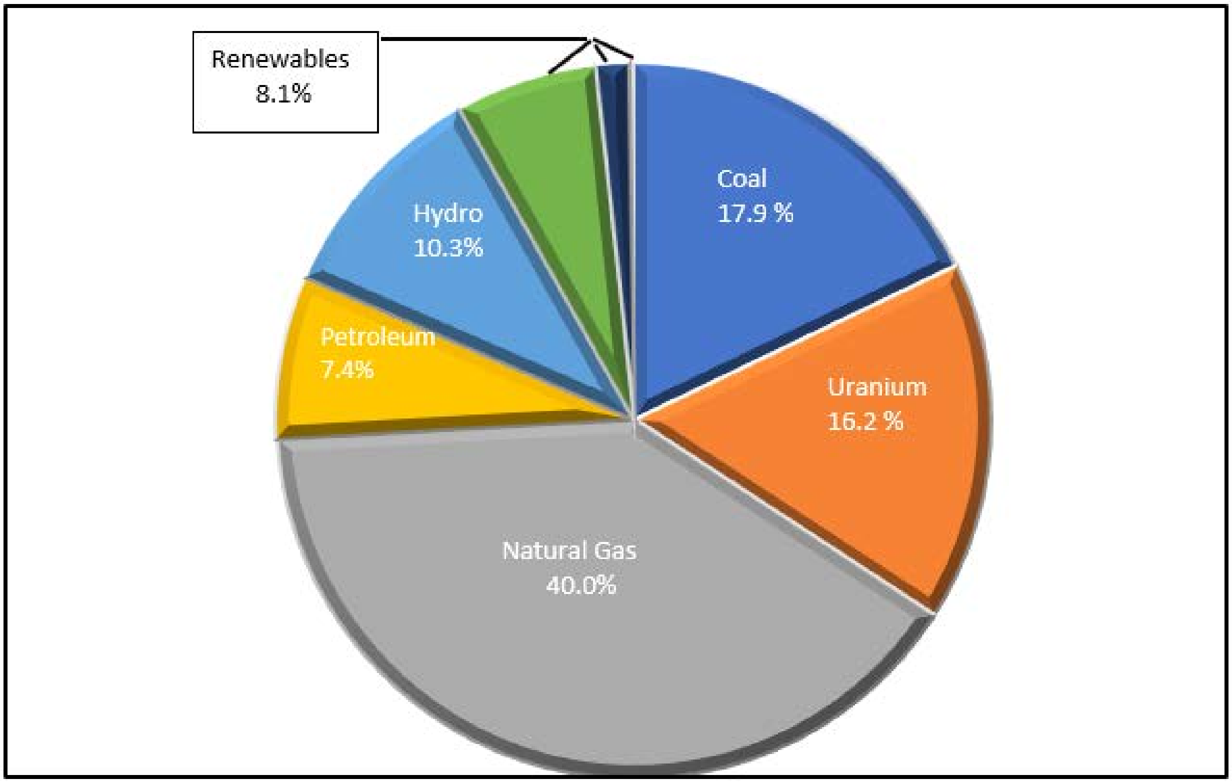

Figure 2 – Company fleet summer capacity (in MW) by fuel type (as of 4th Qtr. 2022)

The Company remains committed to developing a balanced mix of resources that meets the growing needs of customers at the lowest reasonable cost and furthers the Commonwealth's clean energy policy goals and objectives, while also providing fuel diversity for minimizing the risks of changing market conditions, industry regulations, and other factors.

1.2 Fuel Supply Access, Transportation and Storage (Procurement)

The Company's risk management strategy focuses on ensuring reliable and sufficient access to fuel supply at the lowest reasonable cost. Each fuel type's unique characteristics require different procurement strategies based on required volumes, potential price volatility, availability, transportation and storage constraints, and other specific supply concerns. The Company regularly evaluates the requirements for each commodity as markets and operational needs change.

The Company follows a disciplined protocol for procuring fuel from diverse suppliers and supply regions, with various contract terms and prices. This protocol accomplishes two key objectives for the benefit of customers: (1) security of supply and (2) price volatility mitigation. The Company procures fuel for its wholly owned generation assets, through a combination of long- and short-term purchases and daily spot-market transactions. The approach varies, depending on the nature of the fuel, the required volumes, and the associated generating unit type(s). This enables the Company to respond effectively and proactively to generation requirements and commodity price fluctuations.

A key part of ensuring a reliable supply of fuel is securing the transportation of that fuel. Either seasonally or under certain daily or intraday circumstances, the Company may have fuel or capacity that is not needed to support the bidding of units into PJM Interconnection, LLC ("PJM"). At these times, the Company can release the transportation capacity or sell the fuel and return the revenue to the customer in the fuel factor.

1.3 Price Hedging

Uncertainty in future commodity prices exposes the Company and its customers to unpredictable changes in fuel costs. Accordingly, to mitigate the effects of such volatility, the Company enters into physical and/or financial transactions in the marketplace that hedge (i.e., price hedge) against potential future fuel price changes. For purposes of this Report, a price hedge is any transaction, physical or financial, that locks in or fixes some component of the fuel price. Commodity-specific procurement and hedging strategies will be addressed below in Section 2 of this Report.

The objective of the Company's price hedging activity is to mitigate price volatility (i.e., minimize abrupt changes in fuel costs) and provide rate stability, consistent with the Company's public service obligation to provide reliable electric service at the lowest reasonable cost to customers.

Fuel Procurement and Price Hedging Strategy

Overview

The Company is the Commonwealth's largest electric utility, serving approximately 2.6 million customers in Virginia. Reliable service and reasonable rates are critical to the convenience, comfort, and security of these customers, and to the economic well-being of the Commonwealth as a whole.

The objective of the Company's Fuel Procurement Strategy is to provide a framework for implementing a disciplined and prudent procurement and hedging program. The Company uses target ranges for its physical procurement and price hedges, providing for reliability of supply and price risk mitigation while allowing the flexibility needed to adapt to changing market conditions.

Through competitive fuel supply solicitations and other market purchases, the Company maintains a reliable supply of fuel specifically designed for combustion in the Company's generation stations. The terms of these physical procurement agreements are layered (i.e., executed over time). These agreements may or may not include a fixed price; the inclusion of a fixed price creates a price hedge.

Managing price volatility is further supported, as needed, using financial transactions as discussed in Section 5 of this Report. These transactions provide price certainty for commodities whose prices fluctuate based on market conditions. Financial hedge transactions also help guard against commodity price fluctuations resulting from infrastructure limitations or other physical constraints, such as pipeline restrictions due to maintenance or extreme weather conditions (e.g., a polar vortex event).

Prudently incurred fuel procurement and hedging costs are recovered annually subject to Commission Staff audit through a fuel factor filing that estimates a forward-looking fuel factor for the upcoming fuel year (July 1 to June 30) and are adjusted for any under- or over-recovery from the preceding fuel year. The potential variance in fuel costs is a function of weather, the underlying fuel price volatility and the Company's ability to adjust its fleet dispatch to maximize use of the least expensive fuel available to these generation resources.

The following Figure 3 presents the Company's Fuel Procurement and Price Hedging Strategy by fuel type.

Figure 3 - Fuel Procurement and Price Hedging Strategy

	Uranium	Natural Gas	Coal	Purchased Power	Biomass	Petroleum	PPAs
Energy • Forecast Volume Portfolio share[1]	26,830 GWh 28.7%	42,087 GWh 45.1%	12,172 GWh 13%	7,094 GWh 7.6%	1,074 GWh 1.2%	117 GWh <1%	3,958 GWh 4%
Procurement (Physical Supply) Time Period[2]	up to 10 years	up to 3 years	up to 3 years	up to 1 year	up to 3 years		
Target Volume[3]	25-100%	25-100%	60-90%	0-5%	80-90%	100%	100%
Price hedge – Year 1	95-98%	20-50%	60-90%	0-5%	40-70%	100%	80-100%
Physical Transaction Types • Price Hedge[4]	• Fixed price • Inventory on- and off-site	• Fixed price • Fixed basis price • Storage • Transportation • Asset Management Agreement ("AMA")	• Fixed price • Inventory on- and off-site		• Fixed price • Inventory on- and off-site	• Fixed price • Inventory on- and off-site	• Fixed price
• Floating Price	• Index Price	• Index price			• Cost-based • Spot market price	• Index price	• Index price
Financial Transaction Types	• Currency Forwards	• Fixed-price Futures • Basis Futures • Swing Swap Futures • Price Caps and Collars		• Fixed-price Futures • Fixed-price Swap			

Notes:

1. Forecast for July 1, 2022 through June 30, 2023 as of March 31, 2022 (SCC Case No. PUR-2022-00064). The total sum of "Energy Portfolio Share" may not equal 100% due to rounding and the exclusion of hydro and solar resources, which do not require fuel procurement.
2. Under certain circumstances, the Company may choose to enter into a transaction that extends beyond these limits – e.g., if there are specific fuel quality requirements.
3. Based on forecasted volumes as of the May 5, 2022 fuel factor filing in Case No. PUR-2022-00064, except for oil and natural gas, which have procurement targets that may be based on daily peak usage requirements during certain months.
4. These are physical procurement transaction types that have an inherent price hedge through a fixed purchase price.

2.1 Uranium

For purposes of this Report, the nuclear fuel cycle components referenced as "uranium" fuel include uranium ($U_3 0_8$), and conversion, enrichment, and fabrication services. Due to the long lead times involved in the nuclear fuel supply chain, the limited number of suppliers and processing facilities, and the complex nature of the global supply chain, the Company obtains the majority of its supply under a diverse set of long-term supply contracts that are layered over time. The Company also maintains a significant natural uranium inventory and some enriched uranium inventory, when appropriate, to mitigate supply risk. Supply diversity necessitates a balanced set of suppliers, global supply regions, processing facilities, contract terms, and price structures. Components of nuclear fuel may be procured for durations up to the expiration of a unit's operating license, but that would be unusual; the typical term is five (5)-to-ten (10) years. With the exception of fabrication services that are unit- or plant-specific, the Company structures its nuclear fuel contracts to provide supply for any unit in its nuclear fleet. This fleet structure provides the Company greater scale in the market and greater security of supply across the fleet for the benefit of customers.

The Company covers a high percentage of its five-year uranium requirements through inventory and forward contracting. Uranium feed components of nuclear fuel batch costs ($U_3 0_8$ and conversion) are included in the calculation of average inventory accounting, and nuclear fuel batches are amortized consistent with their consumption rates, or "burn-up," across multiple fuel cycles. Additionally, on a typical eighteen (18)-month cycle, the Company replaces one-third of the fuel assemblies in the core. As a result, nuclear fuel expense rates change very gradually over time and are not immediately sensitive to short-term fluctuations in market prices.

Some of the Company's uranium procurement contracts may require payment in foreign currencies. If so, the Company may, at times, use financial transactions to mitigate the impact of changes in the exchange rate between the U.S. Dollar and the applicable foreign currencies.

2.2 Natural Gas

To fuel its natural gas-fired generation stations, the Company procures natural gas supplies, storage, and transportation subject to approved affiliate fuel procurement structures as illustrated in the chart in Figure 4 below.

Figure 4 – Natural Gas Supply, Storage & Transportation Transaction Types

Near Term "Current - 3 Years"	Seasonal Supply Purchases	Financial Hedges	Capacity Releases	AMAs	Peaking Deals
Medium Term "4 - 10 Years"	Term Supply Purchases	Pipeline Capacity	Capacity Releases	AMAs	Peaking Deals
Long Term "11 - 20 Years"	Pipeline Capacity	Storage	AMAs	Peaking Deals	

The Company uses a combination of near- and medium-term supply agreements and near-, medium-, and long-term pipeline capacity agreements to physically secure natural gas supply for its generation stations. Long-term pipeline capacity and storage agreements, and AMAs provide firm deliveries to the Company's generation stations in addition to broadening access to diverse product locations. The Company issues biannual solicitations for fixed-price or index-based physical supplies of natural gas for the upcoming winter (November to March) or summer (April to October) season and subsequent seasons for up to three (3) years. Depending on market conditions and the current transportation and supply portfolio, the Company may issue additional solicitations for physical supply.

To ensure firm gas supply delivery, these near-to-medium-term transactions with suppliers are paired with the Company's pipeline transportation and firm capacity releases. Capacity releases and acquisitions are used to supplement or align with generation and market needs. As part of this process, the Company continually assesses its need for incremental firm pipeline capacity as well as services that address shorter duration peak fueling needs (e.g., natural gas peaking services) while reviewing service offers spanning various terms, with a focus on fuel delivery reliability, fuel portfolio flexibility, and affordability.

Consistent with the policy objectives of the Virginia Clean Economy Act, the Company is committed to achieving net zero emissions by 2050, as part of its clean energy strategy. In the area of fuel procurement, a key aspect of that strategy is reducing emissions generated by the Company's suppliers (Scope 3 emissions), and as such, the Company is evaluating lower emission natural gas, in the form of Certified Natural Gas ("CNG") and/or Renewable Natural Gas ("RNG"). The Company began receiving CNG offers in 2019 as part of its biannual solicitation process. These offers are evaluated consistent with the Company's reliability, service, and cost criteria for natural gas supply.

Strong consideration will be directed to market priced CNG offers from suppliers meeting the Company's reliability and service requirements.

Natural gas has the most potential price volatility of the fuels used for the Company's generation stations. While pricing can be impacted by a wide variety of factors, there are three primary considerations:

1. The overall price level and volatility of natural gas for the U.S. set by large-scale supply economics of drilling, imports/exports of natural gas, and demand.
2. The locational value of natural gas, also called "basis." Over the long-term, basis prices should be set by a combination of marginal transportation costs and market area storage costs that allow natural gas to move from supply regions to demand regions. However, over the short-term, basis prices are subject to significant volatility until capital investment results in infrastructure build.
3. Intra-month and daily physical natural gas markets balance the instantaneous needs of customers – the needs of which can be driven by weather or gas generation outages – and supply. Pipelines provide the linkage between supply and demand by physically moving natural gas to the market area. In real-time, pipeline constraints can limit the ability of the pipeline network to move natural gas from supply basins to the market area. These constraints, coupled with weather-driven demand, have historically resulted in significant price volatility for natural gas, as the Commission has previously recognized when approving the Company's proposed fuel factor rates subject to audit.

With this price volatility in mind, the Company set the price hedge targets illustrated in Figure 5:

Figure 5	Fuel Year		
	1	2	3
Target Price Hedged	20-50%	10-30%	0-15%

To meet the above targets, the Company calculates the percentage of fixed-price natural gas procured compared to the total projected requirement. If the Company is under the target price hedge range using physical transactions, financial transactions may be utilized to supplement the portfolio and mitigate price risk.

Financial derivative contracts are available to hedge against price volatility and include Henry Hub futures contracts, basis futures contracts, and swing swap futures contracts. These financial transactions exist only at highly liquid trading locations and are not available at all of the locations where the Company has fuel requirements. They must be paired with complementary purchases of physical supply and transportation to deliver the needed gas to the required locations for fueling the Company's generating stations. Sellers of these products are generally large financial institutions and merchant gas companies rather than producers. The use of financial derivatives may be subject to additional costs and regulations to initiate and maintain positions. See the glossary of terms at the end of this Report for definitions of available transaction types.

2.3 Coal

The Company sources coal from multiple domestic supply basins, with the majority of purchases from the Central and Northern Appalachia regions. Once the coal has been purchased, it is then transported by rail or truck to the Company's coal-fired electric power plants or off-site storage facilities. The Company targets a system coal inventory range of twenty (20)-to-forty (40) days of full-load operation to ensure reliability for its customers.

Coal is not a readily fungible commodity like natural gas, which has greater market liquidity. To ensure the reliability of coal supply, the Company primarily procures coal under long-term contracts through periodic competitive supply solicitations. The contract terms typically range from one (1)-to-three (3) years; however, under some circumstances, the Company may enter into a transaction that is longer than three years. As market dynamics shift generation toward natural gas, and away from coal, the Company is shortening contract lengths, trending toward shorter durations. The Company maintains a steady supply of coal through a portfolio of layered term agreements that are replaced through new market solicitations as the older agreements expire. In addition to purchases through competitive solicitations, the Company also utilizes short-term spot market purchases, prompt month purchases, and term purchases for supply directly from producers and other sellers.

This type of physical procurement strategy creates a natural price hedge, which mitigates price volatility while helping to ensure a reliable fuel supply for the benefit of the Company's customers.

2.4 Purchased Power

The Company purchases energy from the wholesale market when doing so is more cost-effective than operating its own units. The Company's membership in PJM, a regional transmission organization or entity that coordinates the movement of wholesale electricity in all or part of thirteen states and the District of Columbia, improves the availability and procurement of economical wholesale energy due to the efficiencies of a large power pool. The volume and price of economy purchases are largely established on a day-ahead basis but may also occur on an hourly basis.

The Company may use derivative instruments to financially hedge a certain portion of these volumes, the volume and timing of which are determined in conjunction with natural gas hedging decisions.

2.5 **Biomass**

The Company's biomass units, which primarily burn waste and low-grade wood, all have access to regional wood baskets for their supply of waste wood. The majority of the Company's biomass fuel comes from in-woods chipping operations and sawmill residues.

The Company ensures diversity of supply by obtaining fuel from aggregators as well as directly from producers. Most biomass is sourced within 100 miles of the generating station that will consume it and is delivered by truck. The Company's system inventory for biomass typically ranges from five (5)-to-twelve (12) days of full load operation.

Hopewell and Southampton Power Stations continue to be served by multiple suppliers under both short and long-term agreements, enabling the Company to maintain the reliability of its biomass supply through a diversified supplier base. The Company continues to purchase long-term fuel supply primarily through one supplier at its Altavista Power Station. Procurement for the Company's biomass needs at its co-fired Virginia City Hybrid Energy Center facility continues to be conducted via short- and long-term contracts with various suppliers.

Similar to its coal strategy above and petroleum strategy below, the Company utilizes on- and off-site inventories to ensure adequate physical supply.

2.6 **Petroleum**

The Company sources #2 fuel oil directly from domestic refiners and producers. These suppliers utilize interstate pipelines and domestic barges from distribution points within economical reach of the Company's generation footprint. The Company may also purchase oil from local distributors for direct shipment via tanker trucks. The #2 fuel oil is stored at individual power stations and centralized off-site, third-party terminals where inventory typically ranges from three (3)-to-six (6) days of full load operation.

As with its coal strategy above, the Company utilizes on- and off-site oil inventories to mitigate price risk for its customers.

2.7 Power Purchase Agreements

Power purchase agreements ("PPAs") provide about 4% of the Company's annual load requirement through contracted fossil and renewable-powered generating units. The majority of the Company's PPAs are based on a fixed pricing schedule for energy; however, some of the PPAs are priced based on PJM locational marginal pricing. The current mix of PPAs is trending towards more renewables whose contract prices are reviewed in regulatory proceedings.

3 Historical Fuel Procurement and Hedging Strategy Results

See Figures 6 through 9 below for detail on the Company's hedging and fuel procurement practices from the 2017-2018 Fuel Year through the current 2022-2023 Fuel Year, including (i) the percentage of fuel volumes whose prices were hedged physically and financially by fuel type (Figure 6); (ii) the gains and losses associated with financial hedging activity (Figure 7); (iii) natural gas physical and financial price hedges by type by month (Figure 8); and (iv) an itemized list of costs associated with these financial hedges (Figure 9).

Figure 6 - Fuel Volumes Price Hedged by Fuel Type

Fuel Year Generation Forecast (MWh)	17-18 FY	18-19 FY	19-20 FY	20-21 FY	21-22 FY	22-23 FY
Coal	19,794,471	12,708,432	13,869,471	7,967,160	8,309,590	12,172,090
Natural Gas	29,574,515	36,722,026	38,757,594	39,492,290	38,753,820	42,086,990
Oil	438,451	420,803	228,043	202,900	113,290	116,840
Nuclear	27,520,944	27,782,557	27,491,525	27,578,300	27,616,940	26,830,080
PPA	4,793,571	4,174,990	3,085,057	3,201,770	3,662,770	3,957,780
Purchase	6,081,537	8,270,225	4,060,508	6,262,690	10,403,540	7,094,350
Biomass	1,036,367	1,020,742	900,880	935,460	1,067,950	1,074,900
Hydro	7,517	(101,058)	41,364	40,400	(3,670)	(49,500)
Total	**89,247,373**	**90,998,717**	**88,434,441**	**85,680,970**	**89,924,230**	**93,283,530**

MWh Price Hedged	17-18 FY		18-19 FY		19-20 FY		20-21 FY		21-22 FY		22-23 FY		Hedge Type
Coal	19,596,526	99%	12,454,263	98%	11,637,653	84%	5,205,545	65%	8,309,590	100%	12,172,090	100%	Physical
Natural Gas	-	0%	-	0%	-	0%	-	0%	-	0%	-	0%	Financial
Natural Gas	6,506,393	22%	5,398,138	15%	6,472,518	17%	6,595,212	17%	6,471,888	17%	7,996,528	19%	Physical
Oil	438,451	100%	420,803	100%	228,043	100%	202,900	100%	113,290	100%	116,840	100%	Physical
Nuclear	26,970,525	98%	27,226,906	98%	26,941,694	98%	27,026,734	98%	27,064,601	98%	26,293,478	98%	Physical
PPA	2,636,464	55%	3,214,742	77%	2,385,781	77%	2,476,039	77%	2,887,025	79%	2,770,446	70%	Physical
Purchase	-	0%	-	0%	-	0%	-	0%	-	0%	-	0%	Financial
Biomass	611,457	59%	561,408	55%	414,405	46%	430,312	46%	491,257	46%	752,430	70%	Physical
Hydro	7,517	100%	(101,058)	100%	41,364	100%	40,400	100%	(3,670)	100%	(49,500)	100%	Physical
Total	56,767,334		49,175,202		48,121,457		41,977,142		45,333,981		50,052,313		
% hedged	**64%**		**54%**		**54%**		**49%**		**50%**		**54%**		

MWh Price Hedge figures:
Quantity price hedged at the time of the fuel factor filing for the specified upcoming fuel year (July 1 to June 30).
Percent price hedged is MWh price hedged as a portion of the fuel year forecast.

Prudently incurred gains or losses resulting from any financial hedges are included in the Company's total fuel cost, thus ensuring that all of the costs or benefits associated with the transactions in the Company's price hedging strategy are captured (see Figure 7). Physical fixed-price hedges, by their nature, are procurement transactions and do not have gains or losses. Physical transactions rarely have associated hedging costs, such as broker fees; therefore, there are no material costs to customers.

Figure 7 - Financial Hedging Activity - Settlements/Quantification of Gains and Losses

(A negative value indicates a help to the customer)

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
Natural Gas Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Foreign Exchange Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Power Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total in Fuel Expense	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total
Natural Gas Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Foreign Exchange Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Power Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total in Fuel Expense	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Total
Natural Gas Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Foreign Exchange Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Power Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total in Fuel Expense	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

													Total
Natural Gas Hedge	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	$0
Foreign Exchange Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Power Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total in Fuel Expense	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

													Total
Natural Gas Hedge	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	$0
Foreign Exchange Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Power Hedge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total in Fuel Expense	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Total
Natural Gas Hedge	$0	$0	$0	$0	$0	$0							$0
Foreign Exchange Hedge	$0	$0	$0	$0	$0	$0							$0
Purchased Power Hedge	$0	$0	$0	$0	$0	$0							$0
Total in Fuel Expense	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**							**$0**

Notes: Includes amounts recognized in fuel expense related to ineffectiveness. Beginning in May 2015, ineffectiveness is deferred as a regulatory asset or liability. Beginning in January 2019, ineffectiveness is no longer recorded.
Purchased Power Hedges include option premiums where appropriate.
Natural Gas Hedges do not include transaction costs, which are recovered through base rates and are not recognized in fuel expense.

Figure 8 summarizes the Company's physical and financial natural gas price hedge volumes, by month.

Figure 8 - Natural Gas Price Hedges by Type by Month

Physical Price Hedges by Type

		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	21-22 FY Total
Fixed Basis	Weighted Average Price	$3.07	$3.49	$3.82	$5.29	$5.65	$4.90	$3.47	$5.72	$4.02	$4.79	$6.72	$8.36	$4.93
	Volume	2,790,000	2,790,000	2,700,000	2,790,000	2,700,000	2,790,000	2,790,000	2,520,000	2,790,000	2,700,000	2,790,000	2,700,000	32,850,000
Fixed Price	Weighted Average Price	$2.32	$2.34	$2.53	$3.24	$4.23	$5.70	$5.69	$7.13	$3.61	$2.00	$2.00	$2.00	$3.94
	Volume	5,439,999	5,161,037	5,014,500	2,514,248	2,968,400	5,934,286	5,114,124	4,619,851	1,550,000	1,500,000	1,550,000	1,500,000	42,866,445
Total Physical Hedged Volume		**8,229,999**	**7,951,037**	**7,714,500**	**5,304,248**	**5,668,400**	**8,724,286**	**7,904,124**	**7,139,851**	**4,340,000**	**4,200,000**	**4,340,000**	**4,200,000**	**75,716,445**
		Jul-22	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**22-23 FY Total**
Fixed Basis	Weighted Average Price	$6.00	$8.14	$8.80	$6.32	$4.64	$6.16							$6.68
	Volume	2,790,000	2,790,000	2,700,000	2,790,000	2,700,004	2,790,000							16,560,004
Fixed Price	Weighted Average Price	$2.00	$2.00	$2.00	$2.00	$4.58	$9.28							$4.39
	Volume	1,550,000	1,550,000	1,500,000	1,550,000	2,250,000	2,925,000							11,325,000
Total Physical Hedged Volume		**4,340,000**	**4,340,000**	**4,200,000**	**4,340,000**	**4,950,004**	**5,715,000**	-	-	-	-	-	-	**27,885,004**

Financial Price Hedges by Type

		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	21-22 FY Total
Basis Swap	Settlement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Volume	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Price Swap	Settlement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Volume	-	-	-	-	-	-	-	-	-	-	-	-	-
Swing Swap	Settlement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Volume	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Financial Hedged Volume		-	-	-	-	-	-	-	-	-	-	-	-	-
		Jul-22	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**22-23 FY Total**
Basis Swap	Settlement	$0	$0	$0	$0	$0	$0							$0
	Volume	-	-	-	-	-	-							-
Fixed Price Swap	Settlement	$0	$0	$0	$0	$0	$0							$0
	Volume	-	-	-	-	-	-							-
Swing Swap	Settlement	$0	$0	$0	$0	$0	$0							$0
	Volume	-	-	-	-	-	-							-
Total Financial Hedged Volume		-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 9 shows actual broker fees and other fees associated with financial price hedges through December 31, 2022.

Figure 9 - Costs of Hedging

Purchased-Power Financial Hedge Broker Fees

	17-18 FY	18-19 FY	19-20 FY	20-21 FY	21-22 FY	22-23 FY
Total	$0	$0	$0	$0	$0	$0

Natural Gas Financial Hedge Broker Fees

	17-18 FY	18-19 FY	19-20 FY	20-21 FY	21-22 FY	22-23 FY
Total	$0	$0	$0	$0	$0	$3,852

Natural Gas Financial Hedge Financing Fees

	17-18 FY	18-19 FY	19-20 FY	20-21 FY	21-22 FY	22-23 FY
Total	$0	$0	$0	$0	$0	$0

NOTES:
The purchased power-related broker fees were incurred directly by the Company.

4 Potential Commodity Procurement and Hedging Changes

Currently, the Company does not anticipate making material changes to its commodity procurement or hedging programs in the upcoming 2023-2024 Fuel Year. However, the Company may need to make modifications if market conditions change significantly and will address any such proposed modifications in its upcoming 2023-2024 fuel factor filing, to the extent needed.

5 Fuel Procurement and Hedging Analysis

5.1 Hedging Benefits

The primary benefit of a sound hedging strategy is to stabilize fuel prices, not to ensure below-market prices. This price stabilization, along with a disciplined multiyear, layered procurement program, helps stabilize the cost of fuel and minimize the potential for rate shock on customer bills. A report issued by The National Regulatory Research Institute explains the purpose and benefits of hedging as follows:

As a general proposition, increased fuel volatility harms risk-averse customers. Following standard economic theory, the average household consumer is assumed to be risk averse. On that assumption, the average residential consumer is willing to incur an expense for purposes of avoiding volatile gas bills.[3]

The report continues:

Hedging should not be expected to reduce the average cost of gas purchases over time. Hedging can best be viewed as price insurance purchased for the purpose of avoiding the payment of high gas prices that could occur unexpectedly after the "insurance" is purchased. The intent of hedging is to stabilize prices, not to lower them. As a form of insurance, hedging protects a gas utility and its customers against financial adversity that could otherwise result from being exposed to volatile gas prices.[4]

While the primary benefit of hedging is to stabilize fuel prices, there are additional benefits to customers. For example, regarding natural gas, the Company's semi-annual solicitations effectively minimize or bypass the bid/ask spread by creating a competitive forum with multiple competitive offers across multiple locations. The resulting diverse set of counterparties, including producers, marketers, and financial institutions, allows the Company to choose the best set of transactions for security of supply and hedging to the benefit of its customers. Pipeline capacity to liquid supply regions assists in minimizing fuel costs by providing direct access to natural gas production basins. Physical fuel supply procured through the competitive solicitation process, therefore, incurs no additional costs to a price hedge versus an index-based physical supply purchase.

5.2 Hedging Transaction Fees and Costs

As shown in Figure 9, the Company did not incur any cost from financial hedging through December 31, 2022 of the 2022-2023 Fuel Year.

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[3] Kenneth W. Costello & John Cita, Ph.D., The National Regulatory Research Institute, *Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues* 6-7 (2001). Risk aversion means that individuals and firms are willing to pay something (e.g., a premium) to avoid the possibility of large losses or downward variability in their wealth. *Id.* at 41 n.48.
[4] *Id.* at 40.

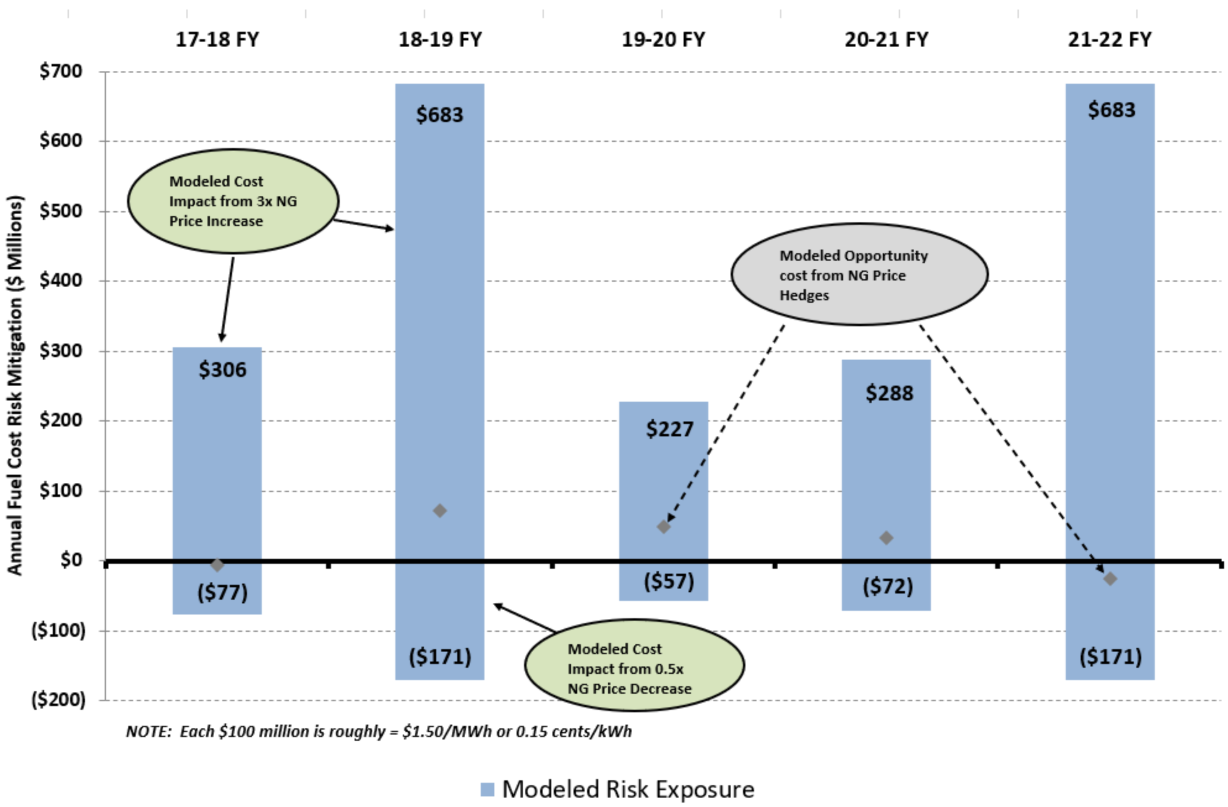
The availability and use of both physical and financial price hedges allow the Company to consider the cost when choosing the most appropriate transaction type. Utilizing a mix of physical and financial hedges can give the Company flexibility to efficiently manage any infrastructure or physical constraints and/or to take advantage of financial market benefits, resulting in a prudent and cost-effective hedging strategy for customers.

With few exceptions, physical purchase transactions can be executed without the need to post cash margins; credit support is most often satisfied using a guarantee or other non-cash alternative. Financial markets, by contrast, generally require the posting of cash margin to ensure the credit risk or market risk associated with the hedge. For example, if capital markets constrict and the cost of hedging using financial products increases, the Company can focus attention on physical markets for hedging. Conversely, when capital markets relax and the cost of financial hedge transactions decreases, at a time when the physical market is unable to provide the size, scope and/or price that the Company is seeking, the Company can take advantage of financial hedge transaction types. See Figures 7 and 9 for a complete listing of financial settlements and hedging costs, respectively, associated with financial hedges.

5.3 **Historical Price Hedge Analysis**

The objective of price hedging is to reduce the volatility in fuel prices, which benefits customers by stabilizing fuel costs. The Company's natural gas financial hedge settlements, physical price triggers and fixed price peaking supply have lessened the impact of natural gas price volatility on historical, total fuel rates. With respect to physical hedges (price triggers), a traditional cost/benefit analysis (as it pertains to hedging gains and losses) is not applicable. A quantification of the cost/savings "lost opportunity" cannot be applied to physical price hedges. Namely, physical purchases that are price triggered, by definition, have been excluded from the supply and demand balance used to calculate the Inside FERC and Gas Daily index or implied cost benchmark(s). However, Figure 10 below is intended to illustrate a modeled, historical hedge benefit analysis. The Company modeled its fuel rates, including any potential changes to the generation mix due to increased natural gas prices, assuming natural gas price swings of 300% (upper, 3X) and 50% (lower, 0.5X). Actual, natural gas fixed price hedges (absolute dollars) were then applied to show the dampening effect of these hedges on modeled fuel costs. Based on this natural gas price swing assumption, over the last five fuel years, natural gas price hedging and generation mix shifts are shown to have reduced customer's fuel cost exposure to natural gas price volatility by an average of approximately $547 million per year. It is important to note the modeled risk exposure (blue bars) are more representative of a winter season, whereas the modeled opportunity cost/gain price point(s) (represented by diamonds) reflect a fuel year.

Figure 10 – Modeled, Historical Natural Gas Hedge Benefit Analysis



5.4 Natural Gas Pipeline Capacity Monetization

Each day, the Company supports gas-fired generation offers into PJM using its firm pipeline capacity portfolio. Per PJM energy market requirements, when the Company determines there is unused firm pipeline capacity, after considering generation offers, awards, flexibility, unit outages, and system constraints, it can offer this capacity, long- or short-term, either in the capacity release or third-party sales market(s). Capacity release or third-party sales decisions are based on a variety of factors including, but not limited to: risk, timing, market availability and perceived market value for the unused firm capacity. All monetization revenues are returned to the Company's customers on a dollar for dollar basis, as a fuel rate offset. See Figure 11 for details pertaining to the Company's natural gas pipeline capacity monetization transactions.

Figure 11 - Natural Gas Capacity Release and Third-Party Sales Monetization

	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	21-22 FY Total
Capacity Release	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 111,527	$ 896,930	$ 11,527	$ 107,930	$ 1,127,914
Third-Party Sales*	$ 317,510	$ 217,284	$ 1,234,933	$ 657,606	$ 272,873	$ (17,898)	$ 11,409,995	$ 312,287	$ 574,586	$ 1,894,737	$ 2,641,080	$ 213,077	$ 19,728,070
Total	**$ 317,510**	**$ 217,284**	**$ 1,234,933**	**$ 657,606**	**$ 272,873**	**$ (17,898)**	**$ 11,409,995**	**$ 312,287**	**$ 686,113**	**$ 2,791,667**	**$ 2,652,607**	**$ 321,007**	**$ 20,855,984**

*Third-party sales revenue are net of estimated cost

5.5 Continuation and Activity of Current Hedging Programs

For commodities such as uranium, biomass, coal, and petroleum, price hedging will continue through the physical procurement process.

The natural gas market has historically been sensitive to unforeseen factors that create significant price volatility. To avoid this uncertainty, it is reasonable to price hedge two (2)-to-three (3) years into the future using a layered procurement approach. Through this layered procurement process, the year-to-year volatility in the cost of the natural gas supplies is dampened. Without such a forward-looking program, customers would be fully exposed to dramatic changes in the natural gas market as they occur.

While the Company has relied upon physical hedges for natural gas procurement for the last several fuel years, market changes, such as more liquidity at trading points where the Company procures natural gas, have increased the likelihood that the Company may resume some level of financial hedging of natural gas.

The use of combined-cycle stations as baseload/intermediate generation, along with combustion turbines as peaking generation, will continue the potential variability of the natural gas portion of customers' fuel bills. For example, actual total natural gas supply costs for 2022 exceeded $1.5 billion. Given the continued evolving nature of natural gas markets, a forward-looking procurement and price hedging program is a prudent step to mitigate potential cost volatility for the benefit of customers.

The natural gas market allows procurement at an index price, permitting the Company to procure physical supply while leaving the price to float until the index is set. This provides the option to separate the price-hedge transactions from procurement of physical supply. Current market dynamics also allow physical-supply transactions inclusive of a price-hedge component, at no additional cost. The Company believes that prudently executed physical supply purchases containing a price-hedge component at no additional transaction cost reduce the variability of the fuel portion of customer bills and are in customers' best interests. The Company's current natural gas price hedge ranges are designed to hedge baseload volumes. For details and analysis supporting the Company's price hedge targets, see the section titled "Why use a 20% to 50% range for hedged volumes" in Appendix D of the Company's 2015 Fuel Procurement Strategy Report filed on January 30, 2015 in Case No. PUE-2014-00033.

Glossary of Terms

Ask Price or Offer Price indicates a willingness to sell a commodity at a given price.

Asset Management Agreements (AMAs) are a common arrangement with sellers that allows for the bundling of a package of fuel supply with corresponding transportation and delivery options (including storage), resulting in both reliable supply and transport at either the then-current or index-based pricing. Terms vary from one season to multiple years. AMAs can be transacted at a fixed or capped price.

Basis Futures Contracts are financial derivatives cleared through an exchange or clearinghouse whose pricing terms represent the then-current market value of the delivery location relative to Henry Hub. Settlement gains and losses are calculated by taking the difference between the final settlement value of the delivery location relative to Henry Hub and the pricing terms. These markets are available at highly liquid points only for monthly, seasonal, or annual terms.

Bid Price is an offer to buy a specific quantity of a commodity at a stated price or the price that the market participants are willing to pay.

Bid/Ask Spread is the price difference between the Bid and Ask Prices.

Broker Fees are commissions paid per transaction to brokers for executing the Company's orders. Brokers assist in finding a liquid and competitive price; in addition, they can be used to ensure the buyer's anonymity during a transaction. Brokers can be used in both physical and financial transactions. Broker fees paid by the Company for each of the last five fuel years, as well as for the 2022-2023 Fuel Year through December 31, 2022, can be found in Figure 9 of this Report.

Capacity Release is the temporary release of firm transportation services.

Credit Risk is the potential non-payment and non-performance of a counterparty on a contract to buy or deliver fuel. Potential loss of a hedge would occur under a counterparty bankruptcy during which the counterparty ceases to perform on a set of transactions. Cleared and bilateral financial transactions have margining provisions to significantly mitigate any value loss from a counterparty credit event. Physical transactions do not have margining provisions. All transactions must comply with the Company's credit policies.

Currency Forward is a financial derivative that is entered into by the Company for the purpose of price hedging a foreign currency exchange rate.

Exchange & Clearing Fees are fees paid if a transaction is conducted through an exchange or a clearinghouse, such as the Intercontinental Exchange ("ICE") or New York Mercantile Exchange ("NYMEX"), or is cleared through a clearinghouse. Exchange and clearing fees paid by the Company for each of the last five fuel years, as well as for the 2022-2023 Fuel Year through December 31, 2022, can be found in Figure 9 of this Report.

Financial Transaction or Financial Hedge is a financial derivative that is entered into by the Company for the purpose of price hedging. Financial transactions provide a price hedge without requiring delivery of a physical commodity. Gains and losses are calculated by taking the difference between the transaction price and a published index price for the fuel. Financial transactions include swaps, futures contracts, and price caps and collars that do not require physical delivery of fuel.

Fixed-Basis Physical Transaction is a physical fuel contract that has fixed pricing terms based on the then-current market value of the delivery location relative to the Henry Hub, as well as a floating index price based on the Henry Hub price. This basis differential is fixed while the Henry Hub price will float until the week immediately preceding the month that the gas will flow. These contracts can be arranged to allow the Company the right, at a later date, to fix the Henry Hub-based component of the price.

Fixed-Price Futures Contracts are financial transactions traded on an exchange or through a clearinghouse that are priced at the then-market price for a delivery location. Settlement gains and losses are calculated by taking the difference between the settled price at the delivery location and the transaction price. These contracts are liquid and available for monthly, seasonal, or annual terms.

Fixed-Price Physical Transaction is a procurement purchase which establishes a locked-in fixed price for the total value of the fuel at the then-current market price. This is a type of price hedge.

Fixed-Price Swaps are similar to Fixed-Price Futures Contracts except that they are not traded through an exchange or clearinghouse.

Hedge or Price Hedge is any one-month or longer transaction, physical or financial, which fixes some component of the price of the fuel for a portion or all of the period of the transaction.

Henry Hub Futures Contracts are financial transactions that are priced at the then-market price at Henry Hub, a liquid natural gas trading point. Gains and losses are calculated by taking the difference between the settled Henry Hub price, as determined by the NYMEX, and the transaction price.

Index-Priced Fuel has pricing that floats with a published market price. The final price of fuel is based on the published index, which may settle quarterly, monthly, or daily.

Margining is the posting of good-faith collateral to reduce credit risk. Margin posted may include cash, financial instruments such as Treasury bonds or letters of credit, or guarantees. Exchanges and clearinghouses generally require the posting of cash, while financial or physical transactions with non-exchange counterparties may require cash, financial instruments, or guarantees.

Natural Gas Peaking Deals are seasonal (typically winter period) natural gas supply deals that offer supply at one or various strategic, delivered locations, where supply may be needed during peak periods. Pricing structures typically include both a fixed and variable cost component and are usually at elevated price levels, due to expected delivery during peak period(s).

Pipeline Capacity Contracts are firm capacity services on pipelines that can deliver oil or natural gas to the Company's generation or storage facilities in a reliable manner. Natural gas pipeline capacity contracts allow the Company to purchase supply in more liquid and less constrained supply basins, rather than in more often constrained and volatile market delivery areas.

Price Caps & Collars are fuel purchased with a capped price in return for a fee. A collar provides a band within which the price will float, with a cap that the price will not exceed and a floor limiting how low the price can decline. Caps and collars can also be executed through financial transactions, puts, and calls.

Procurement is the collective purchasing of physically delivered fuel, transportation, or storage products.

Swing Swap Futures Contracts are financial transactions that have a transaction price equal to the then-current market value of locking in a fixed price every day in a month based on the settled monthly referenced basis location. Settlement gains and losses are calculated by taking the difference of the average daily market price at the referenced basis location and the fixed monthly index price at that location.

CERTIFICATE OF SERVICE

I hereby certify that on this 31st day of January 2023, a true and accurate copy of the foregoing filed in Case No. PUR-2022-00064 was hand delivered, electronically mailed, and/or mailed first class postage pre-paid to the following:

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/s/ Elaine S. Ryan

**DIRECT TESTIMONY OF
CHRISTOPHER D. CLEMENS
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 675**

Q. Please state your name, position, business address, and responsibilities.

A. My name is Christopher D. Clemens, and I am the Supervisor of Fuel Procurement Engineering in the Nuclear Fuel Procurement Group. My business address is Innsbrook Technical Center, 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am responsible for nuclear fuel fabrication procurement, fuel-related project management, and nuclear fuel fabrication price forecasting and budgeting used by Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina (the "Company"). A statement of my background and qualifications is attached hereto as Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the nuclear fuel market and any significant impact of the market on nuclear fuel costs during the test period of July 1, 2022 through June 30, 2023 ("Test Period"), in compliance with Commission Rule R8-55(e)(5). Section I of my testimony will discuss the market and components of the Company's nuclear fuel costs. Section II will discuss how the Company's nuclear fuel expense rates are calculated.

Q. Please briefly describe the Company's nuclear fuel procurement policy.

A. The Company continues to follow the same procurement practices as it has in the past in accordance with its procedures, a copy of which has been previously provided to this Commission in Docket No. E-100, Sub 47A. These procedures not only cover nuclear fuel procurement, but also the procurement of natural gas, coal, biomass, and oil.

SECTION I
NUCLEAR FUEL MARKET AND COMPONENTS

Q. What are the major components of nuclear fuel expenses?

A. Nuclear fuel expenses include the amortized value of the cost for uranium, along with required conversion, enrichment, and fabrication services (collectively the "front-end components"). In addition, there is the amortization of the Allowance for Funds Used During Construction ("AFUDC") and the federal government's fee for the disposal of spent nuclear fuel. I will discuss the current status of the disposal fee in Section II of my testimony.

Q. Please describe any changes in the market conditions for the front-end components since the last fuel proceeding.

A. Generally, the late February 2022 Russian invasion of Ukraine and the resulting ongoing conflict has continued to impact the front-end nuclear fuel component markets, with the impacts on conversion and enrichment markets being the most pronounced. Both spot and term prices for conversion and enrichment are significantly higher and are likely to remain higher than prior to the invasion, due to the prospect of Russian supply becoming limited or unavailable.

Russia is a major global nuclear fuel supplier, particularly with respect to uranium enrichment. While supply to the United States ("U.S.") was already limited by the previously existing Russian Suspension Agreement, impacts to global supply affect global market pricing. Thus, the potential for an immediate and indefinite cutoff of Russian supply to the U.S.—and potentially other Western utilities through sanctions, bans, or other government actions—would have certain and near immediate impacts on conversion and enrichment supply to the U.S. and other Western markets. Additionally, and to reduce dependence on Russian supply, the pricing required to support long-term investment in new Western production capacity is driving market pricing for conversion and enrichment. Finally, uranium pricing—especially term pricing—is also now more tied to incremental pricing required for new production investment required to support anticipated future growth in global nuclear power generation, though this market change was an expected and increasing trend prior to the Russian invasion of Ukraine.

More specifically, since the ending market timeframe of late June 2022 through the end of May 2023, the market price for spot uranium has increased approximately \$5.60/lb U_3O_8[1] (or 11%) and term base escalated prices for

[1] Pricing units represented in this testimony, *i.e.*, \$/lb U_3O_8, \$/kgU, and \$/SWU (Separative Work Unit) are standard units of measure in sourcing uranium and associated services related to the nuclear power industry. Market pricing is based on data from Ux Weekly published by UxC LLC.

uranium have increased approximately $5/lb U_3O_8 (or 10%). While the Russian invasion of Ukraine has certainly contributed to uranium price volatility, price is also still significantly influenced by financial fund purchasing. A disruption of Russian uranium supply would not be as significant for the uranium market, compared to conversion and enrichment, as there are already numerous opportunities to restart idled uranium production, as well as developing new production, in various countries worldwide. These production sources could come to bear in the near to intermediate timeframe.

Conversion prices have also increased during the June 2022 to May 2023 timeframe. The market price for spot conversion increased approximately $8.25/kgU (or 16%) and term base escalated prices for conversion in the same period have increased approximately $4/kgU (or 16%). Conversion has been impacted significantly by the Russian invasion, as a cutoff of Russian supply would greatly stress available conversion capacity. This would be compounded by additional conversion demand from the change in enrichment operations that would be needed to free up available centrifuge capacity to address the loss of Russian enrichment. Additionally, more Western conversion capacity will be needed as soon as it can be brought online, and any delay in the anticipated restart of the Honeywell uranium conversion plant in Metropolis, Illinois in mid-year of 2023 will add to a constrained supply situation and increase supply risk.

Similarly, enrichment pricing has shifted since early last year. The market price for spot enrichment has increased approximately $47/separative work unit ("SWU") (or 54%) and term base escalated prices for enrichment in the same period have increased approximately $11/SWU (or 8%). Again, the prospective loss of Russian supply is impacting prices due to the anticipated need of additional Western enrichment capacity in the market to supplant that loss. There is also the potential for additional increases in enrichment cost to support investment in new enrichment capacity.

Finally, the price trend in the U.S. domestic nuclear fuel fabrication continues to be difficult to measure because there is no active spot market, but the industry consensus is that costs will continue to increase due to regulatory requirements, reduced competition, new reactor demand abroad, and inflationary pressures on commodities used by the fabricators. With respect to the fabrication market, the U.S. has not experienced any significant impacts due to the conflict in Ukraine, as Russian fabrication is not relied upon by Western utilities.

Q. Have these changes in market costs impacted the Company's projected near-term costs?

A. Yes, but not significantly. The Company's current mix of longer-term front-end component contracts has reduced its exposure to the market volatility that has occurred over the past several years. In addition, because the Company's nuclear plants replace about one-third of their fuel on an 18-month schedule, there is a delay before the full effect of any significant changes in a component price is seen in the plant operating costs.

SECTION II
NUCLEAR FUEL EXPENSE RATES

Q. Would you please describe how the Company's nuclear fuel expense rates are developed?

A. The calculation of nuclear fuel expense rates, expressed in mills per kilowatt-hour ("mills/kWh"), is based on expected plant operating cycles and the overall cost of nuclear fuel. As I stated above, front-end component costs include uranium, conversion, enrichment, and fabrication services. These costs, along with AFUDC, are amortized over the energy production life of the nuclear fuel. The federal government's fee, applied to net nuclear generation sold, would also typically be included in the expense rate. This cost, applied to all U.S. nuclear generation companies, is intended to cover the eventual disposal cost of spent nuclear fuel in a federal repository. However, the fee, which historically has been one mill/kWh of net nuclear generation, is currently set to zero mills/kWh and is not collected.

Q. Please provide an update regarding the status of this fee.

A. In 2014, following a federal court decision, the U.S. Department of Energy ("DOE") submitted a proposal to Congress to change this one mill/kWh fee to zero. This relief is industry-wide and applies to all operating reactors, including the Company's operating reactors at the Surry and North Anna Power Stations. As of May 16, 2014, the Company is no longer required to pay the waste fee.

Q. Can the waste fee collected by the federal government be reinstated?

A. Yes, it can. As explained in previous testimony, the Nuclear Waste Policy Act allows the Secretary of Energy to review fee adequacy on an annual basis. It is likely that at some point in the future when a viable waste disposal program is established by DOE, the Secretary will develop an adjustment to the waste fee that ensures full cost recovery for the life cycle of such a program. Any proposed adjustment to the fee will again need to be submitted to Congress for review. If and when a fee adjustment becomes effective, the Company will again become obligated to make the fee payment, and will again seek to recover payments for the assessed fee in its fuel factor.

Q. What was the fuel expense rate for the Test Period?

A. The fuel expense rate is provided in Company Exhibit JDM-1 to the Direct Testimony of Company Witness Jeffrey D. Matzen.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
CHRISTOPHER D. CLEMENS

Christopher D. Clemens is a graduate of Pennsylvania State University with a Bachelor of Science degree in Nuclear Engineering (1998), and a Master's degree in Business Administration from Virginia Commonwealth University (2007).

Mr. Clemens joined Virginia Electric and Power Company in 1998, and has worked since then in staff and management positions involving nuclear fuel. His current responsibilities include procurement of nuclear fuel fabrication and related services, nuclear fuel-related project management, and the projection of nuclear fabrication prices and related capital costs and expense rates.

DIRECT TESTIMONY
OF
TIMOTHY P. STULLER
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 675

Q. Please state your name, business address, and position of employment.

A. My name is Timothy P. Stuller. My business address is 120 Tredegar Street, Richmond, Virginia 23219. My title is Manager - Regulation for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina (the "Company"). A statement of my background and qualifications is attached as Appendix A.

Q. Mr. Stuller, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the Company's derivation of the proposed Fuel Cost Rider A and the proposed Experience Modification Factor ("EMF") Rider B for the North Carolina Jurisdiction and for each customer class based on the 12 months ended June 30, 2023 (the "Test Period"), to become effective on February 1, 2024. I am also sponsoring the calculation of the adjustment to total system sales (kWh) for the 12 months ended June 30, 2023, due to change in usage, weather normalization, and customer growth.

Q. Do you sponsor any exhibits?

A. Yes. Company Exhibit TPS-1, consisting of 10 schedules, was prepared under my direction and is accurate and complete to the best of my knowledge and belief.

Q. What is the total fuel factor that the Company is proposing in this case?

A. I have calculated the North Carolina jurisdictional average fuel factor equal to the combined base fuel and Fuel Cost Rider A, excluding Rider B (the Experience Modification Factor) ("EMF") and Rider B1 for the Test Period ending June 30, 2023, to be $0.034575/kWh.

Q. Mr. Stuller, please explain Schedule 1.

A. Schedule 1 of Company Exhibit TPS-1 provides a summary of jurisdictional and total system kWh sales for the 12 months ended March 31, 2023, adjusted for change in usage, weather normalization, and customer growth. Line 1 of Schedule 1 shows the adjustment to sales for the North Carolina Jurisdiction of 71,024,667 kWh. The adjustment to total system kWh at sales level is 4,626,779,594 kWh. This adjustment is consistent with the methodology used in the Company's last general rate case (Docket No. E-22, Sub 562) and the last fuel charge adjustment case (Docket No. E-22, Sub 644).

Q. Have you calculated the proposed Fuel Cost Rider A for the North Carolina Jurisdiction and each customer class?

A. Yes. Schedule 2 of Company Exhibit TPS-1 presents the calculation of the proposed System Average Fuel Factor for the North Carolina Jurisdiction and for each customer class. On Schedule 2, Page 1, a system fuel expense level of $3,242,280,682 (as provided in Schedule 4 of Company Exhibit JDM-1) is divided by system sales of 93,914,081,594 kWh that reflect the normalization adjustments for change in usage, weather, and customer growth, and adjusted for the North Carolina regulatory fee. The result is a normalized system average fuel factor of $0.034575/kWh, applicable to the North Carolina Jurisdiction. The calculations used to differentiate the jurisdictional Base Fuel Component by voltage to determine the class fuel factors are shown on Schedule 2, Page 2. They are consistent with the methodology used in the Company's most recent fuel case (Docket No. E-22, Sub 644). The Base Fuel Component for each class determined in Docket No. E-22, Sub 644 is shown in Column 8 of Schedule 2, Page 2. Fuel Cost Rider A is calculated in Column 9 of Schedule 2, Page 2.

Q. The Test Period for the growth and weather normalization adjustments is different than in years past, please describe and justify that difference?

A. The Company's transition to a new customer information platform has resulted in delays in the availability of sales information in the formats required for input to the models which determine the change in usage, weather normalization, and customer growth. In an effort to produce an accurate adjustment in a timely manner for the current proceeding, the Company developed the normalization adjustments using the 12 months ended March 31, 2023. It is important to note that the 12 months used for the normalization adjustments are only used for the purpose of producing the adjustments for change in usage, weather normalization, and customer growth as well as the class breakdown of the total Test Period sales. The methodology for applying the adjustments has not changed.

Q. Mr. Stuller, would you address the final stipulation mitigation methodology from last year's fuel proceeding, Docket No. E-22, Sub 644?

A. The final mitigation methodology approved by the Commission was a special treatment of the August 31, 2022, under-recovery of $66,729,993 for all customer classes. The treatment was termed "Stepped Mitigation." Stepped Mitigation resulted in a "Step 1" Rider B rate ($0.004764) that significantly reduced the "Full Recovery" rate for the rate year beginning February 1, 2023 which would remain in place for the first six months of the fuel rate year. The "Step 2" rate, which became effective August 1, 2023 and remains in place for the second six months of the fuel rate year is the fully supported Rider B rate for the period ($0.01597). This mitigation was expected to leave a significant portion of the original EMF balance from August 31, 2022 unrecovered during the 2023 fuel rate year. In order to separate the under recovery due to mitigation from the recovery of current period expense that will be recovered through Rider B, the Company is proposing rates to recover the projected remaining balance of the prior period fuel expense, through a mechanism termed "Rider B1," in the 2024 fuel year. In the 2024 fuel proceeding, the Company will establish Rider B1 rates to recover or refund during the 2025 fuel year any final over or under-recovery of the August 31, 2022, balance.

Q. Please describe the Experience Modification Factor, Rider B.

A. Schedule 3 of Company Exhibit TPS-1 presents the calculation of the proposed EMF Rider B applicable to the North Carolina Jurisdiction and the resulting factors for each customer class. Schedule 3, Page 1, shows the calculation of the proposed uniform EMF applicable to the North Carolina Jurisdiction. The total under-recovered current period fuel expense, for the period September 1, 2022, through June 30, 2023, of $17,578,384 (as provided in Schedule 2 of Company Exhibit AJM-1) was not adjusted for interest. The total net balance of $17,578,384 was then divided by North Carolina test year sales of 4,013,280,667 kWh which have been adjusted for change in usage, weather, and customer growth. After being adjusted for the North Carolina regulatory fee, the result is a uniform EMF of $0.004386/kWh, applicable to the North Carolina Jurisdiction. The calculations used to differentiate the uniform factor by voltage to determine the class factors are shown on Schedule 3, Page 2. The resulting EMF for each class is shown in Column 7 of Schedule 3, Page 2.

Q. Do you have a schedule that shows the projected outstanding balance to be recovered through the proposed Rider B1 mechanism?

A. Yes. Schedule 4 of Company Exhibit TPS-1 shows the projected recovery of prior period expense through the remainder of the 2023 fuel rate year.

Q. Do you have a schedule that shows the derivation of the proposed Rider B1 rates?

A. Yes. Schedule 5, Pages 1 and 2, of Company Exhibit TPS-1 shows the calculation of Rider B1 rates based on the projected balance calculated in Schedule 4. The methodology to determine the Rider B1 class factors is the same as the methodology used to determine the Rider B rates, shown in my Schedule 3 and described above. The total projected January 31, 2024 balance of $26,638,591 was then divided by North Carolina test year sales of 4,013,280,667 kWh which have been adjusted for change in usage, weather, and customer growth. After being adjusted for the North Carolina regulatory fee, the result is a uniform EMF of $0.006648 /kWh, applicable to the North Carolina Jurisdiction. The calculations used to differentiate the uniform factor by voltage to determine the class factors are shown on Schedule 5, Page 2. The resulting EMF for each class is shown in Column 7 of Schedule 5, Page 2.

Q. Please provide a summary of the total fuel factors that the Company is requesting in this case for each class to become effective February 1, 2024.

A. The total proposed fuel rates ($/kWh) for each class are as follows:

Customer Class	Total
Residential	$0.046082
SGS & PA	$0.046038
LGS	$0.045713
Schedule NS	$0.044299
6VP	$0.044937
Outdoor Lighting	$0.046082
Traffic	$0.046082

A comparison of the present and proposed total rates for each class is shown on Schedule 6, Pages 1 and 2, of Company Exhibit TPS-1.

Q. Do you have a schedule that shows the total fuel revenue recovery by class and for the North Carolina Jurisdiction for the 2024 Rate Year?

A. Yes. Schedule 7 of Company Exhibit TPS-1 shows the total fuel revenue recovery by class and for the North Carolina Jurisdiction for the 2024 Rate Year. For the North Carolina Jurisdiction, the proposed jurisdictional fuel cost levels result in a total fuel recovery decrease of $4,326,317.

Q. Have you included in your exhibit revisions to the Fuel Cost Rider A and EMF Rider B as well as Rider B1 to reflect the Company's proposed total fuel factors, to be effective February 1, 2024?

A. Yes. Schedules 8, 9, and 10 of Company Exhibit TPS-1 provide the revised Fuel Charge Rider A and EMF Rider B as well as Rider B1 that the Company proposes to become effective on and after February 1, 2024.

Q. Mr. Stuller, would you explain how these proposed changes in the fuel factor will affect customers' bills? Use bill amounts as of August 1, 2023 as a point of reference.

A. For Rate Schedule 1 (residential), for a customer using 1,000 kWh per month, the weighted monthly residential bill (four summer months and eight base months) would decrease by $1.11 from $137.44 to $136.33, or by 0.8%. For Rate Schedule 5 (small general service), for a customer using 12,500 kWh per month and 50 kW of demand, the weighted monthly bill (four summer months and eight base months) would decrease by $13.58 from $1,403.33 to $1,389.75, or by 1.0%. For Rate Schedule 6P (large general service), for a primary voltage customer using 576,000 kWh (259,200 kWh on-peak and

316,800 kWh off-peak) per month and 1,000 kW of demand, the monthly bill would decrease by $614.59 from $53,036.63 to $52,422.04, or by 1.2%. For Rate Schedule 6L (large general service), for a primary voltage customer using 6,000,000 kWh (2,400,000 kWh on-peak and 3,600,000 kWh off-peak) per month and 10,000 kW of demand, the monthly bill would decrease by $6,402.00 from $518,678.31 to $512,276.31, or by 1.2%.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF TIMOTHY P. STULLER

Timothy P. Stuller, Jr. holds a Bachelor of Science degree in Economics and Business from Randolph – Macon College and a Master of Business Administration from Virginia Commonwealth University. In 2007, Mr. Stuller joined Dominion Energy as a Regulatory Accounting Analyst I. In 2009, Mr. Stuller moved to the Customer Rates department as Regulatory Analyst II. Since 2009, Mr. Stuller has held various roles in the Customer Rates department including cost of service study development, analysis of rates and tariffs, supporting non-jurisdictional contracts, and generally supporting regulatory filings. Most recently, Mr. Stuller's primary responsibility was analysis and design of rates to recover fuel costs for customers across the Dominion Energy Virginia and Dominion Energy North Carolina systems. On July 1, 2023, Mr. Stuller assumed his current role, Manager-Regulation, and will be responsible for tariff implementation and the negotiation and administration of the Company's wholesale and large customer sales contracts.

Mr. Stuller has previously testified before the North Carolina Utilities Commission and the Virginia State Corporation Commission.

DOMINION ENERGY NORTH CAROLINA
SUMMARY OF KWH ATTRIBUTABLE TO
CHANGE IN USAGE, WEATHER NORMALIZATION, AND CUSTOMER GROWTH

TWELVE MONTHS ENDED MARCH 31, 2023

SYSTEM

LINE	JURISDICTION	CHANGE IN USAGE KWH	WEATHER NORM. KWH	CUSTOMER GROWTH KWH	TOTAL KWH
1)	NORTH CAROLINA (A)	11,031,055	33,962,412	26,031,200	71,024,667
2)	VIRGINIA	3,516,310,283	550,500,198	182,615,271	4,249,425,752
3)	COUNTY & MUNICIPAL	58,803,470	2,572,908	117,275,581	178,651,959
4)	STATE	58,842,134	(21,357,555)	67,376,434	104,861,013
5)	MS / FEDERAL GOVERNMENT	0	0	0	0
7)	FERC	0	22,816,203	0	22,816,203
8)	SYSTEM KWH AT SALES LEVEL	3,644,986,942	588,494,166	393,298,486	4,626,779,594
9)	SUBTOTAL - SYSTEM KWH AT GENERATION LEVEL (LINE 8 x 2022 EXPANSION FACTOR) (B)				4,830,894,602

NOTES

( ) DENOTES NEGATIVE VALUE

(A) NORTH CAROLINA BY CLASS	CHANGE IN USAGE KWH	WEATHER NORM. KWH	CUSTOMER GROWTH KWH	TOTAL KWH
RESIDENTIAL	(21,878,674)	32,740,512	5,835,963	16,697,801
SGS / PA	(4,395,911)	1,221,900	12,029,591	8,855,580
LGS	(7,038,984)	0	6,693,017	(345,967)
NS	40,024,754	0	0	40,024,754
6VP	4,985,608	0	0	4,985,608
ODL & ST LTS	(664,401)	0	1,470,068	805,667
TRAFFIC	(1,337)	0	2,561	1,224
TOTAL	11,031,055	33,962,412	26,031,200	71,024,667

(B) 2022 SYSTEM EXPANSION FACTOR IS 1.044116

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF SYSTEM AVERAGE FUEL FACTOR
TWELVE MONTHS ENDED JUNE 30, 2023
TO BE EFFECTIVE FEBRUARY 1, 2024

EXPENSE:	12 MONTH NORMALIZED SYSTEM FUEL EXPENSE (A)	$	3,242,280,682
SALES:	12 MONTHS SYSTEM KWH SALES ADJUSTED FOR CHANGE IN USAGE, WEATHER AND CUSTOMER GROWTH (B)		93,914,081,594
FEE:	NORTH CAROLINA REGULATORY FEE ADJUSTMENT FACTOR		1.001475

FACTOR = $\frac{\$3,242,280,682}{93,914,081,594}$ x 1.001475

FACTOR = $0.034575 / KWH (C) (D)

NOTES

(A) FROM COMPANY EXHIBIT JDM-1 SCHEDULE 4

(B)	SYSTEM KWH AT SALES LEVEL [COMPANY EXHIBIT AJM-1, SCHEDULE 3]	89,287,302,000
	PLUS: SYSTEM KWH USAGE, WEATHER, GROWTH ADJUSTMENT [COMPANY EXHIBIT TPS-1, SCHEDULE 1, LINE 8]	4,626,779,594
	TOTAL SYSTEM SALES	93,914,081,594

(C) THE NORTH CAROLINA JURISDICTIONAL BASE FUEL FACTOR IS $0.02092/KWH

(D) WITHOUT NC REGULATORY FEE $0.034524 /KWH

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF FUEL COST RIDER A
TWELVE MONTHS ENDED JUNE 30, 2023
TO BE EFFECTIVE FEBRUARY 1, 2024

	(1)	(2)	(3)		(4)	(5)		(6)	(7)	(8)	(9)
CUSTOMER CLASS	KWH SALES (A)	SYSTEM FUEL FACTOR (B)	FUEL REVENUE UNIFORM RATE (1) x (2)		CLASS EXPANSION FACTOR	CLASS KWH @ GENERATION LEVEL (1) x (4)		JURISDICTIONAL UNIFORM RATE @ GENERATION LEVEL (3a) / (5a)	JURISDICTIONAL VOLTAGE DIFFERENTIATED RATE @ SALES LEVEL (4) x (6)	VOLTAGE DIFFERENTIATED BASE FUEL RATE	FUEL COST RIDER A RATE (7) - (8)
RESIDENTIAL	1,577,823,651	$0.034575	$54,553,253		1.053586	1,662,372,909		$0.033157	$0.034934	$0.021180	$0.013754
SGS & PA	762,250,648	$0.034575	$26,354,816		1.052612	802,354,179		$0.033157	$0.034901	$0.021150	$0.013751
LGS	631,266,126	$0.034575	$21,826,026		1.045160	659,774,105		$0.033157	$0.034654	$0.020980	$0.013674
SCHEDULE NS	733,864,312	$0.034575	$25,373,359		1.012814	743,268,049		$0.033157	$0.033582	$0.020360	$0.013222
6VP	284,558,909	$0.034575	$9,838,624		1.027402	292,356,392		$0.033157	$0.034066	$0.020650	$0.013416
OUTDOOR LIGHTING	23,121,607	$0.034575	$799,430		1.053586	24,360,601		$0.033157	$0.034934	$0.021180	$0.013754
TRAFFIC	395,414	$0.034575	$13,671		1.053586	416,603		$0.033157	$0.034934	$0.021180	$0.013754
TOTAL	4,013,280,667		$138,759,179	(3a)		4,184,902,838	(5a)				

NOTES

(A)

	TEST YR KWH	CHG IN USAGE, WEATHER CUST GROWTH ADJ	TOTAL*
RESIDENTIAL	1,561,125,850	16,697,801	1,577,823,651
SGS & PA	753,395,068	8,855,580	762,250,648
LGS	631,612,093	(345,967)	631,266,126
SCHEDULE NS	693,839,558	40,024,754	733,864,312
6VP	279,573,301	4,985,608	284,558,909
OUTDOOR LIGHTING	22,315,940	805,667	23,121,607
TRAFFIC	394,190	1,224	395,414
TOTAL	3,942,256,000	71,024,667	4,013,280,667

* CLASS KWH AT SALES LEVEL PLUS CHANGE IN USAGE, WEATHER NORMALIZATION, AND CUSTOMER GROWTH [COMPANY EXHIBIT TPS-1 SCHEDULE 1]

(B) IN $/KWH

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF EXPERIENCE MODIFICATION FACTOR - RIDER B
TWELVE MONTHS ENDED JUNE 30, 2023
TO BE EFFECTIVE FEBRUARY 1, 2024

EXPENSE:	SEPTEMBER 1, 2022 - JUNE 30, 2023 NC JURISDICTIONAL FUEL EXPENSE UNDER RECOVERY (A)	$17,578,384
INTEREST:		$0
NET:		$17,578,384
SALES:	12 MONTHS JURISDICTIONAL KWH SALES ADJUSTED FOR CHANGE IN USAGE, WEATHER, AND CUSTOMER GROWTH (B)	4,013,280,667
FACTOR (Excl. Reg Fee) =	$0.004380 / KWH (C)	
FEE:	NORTH CAROLINA REGULATORY FEE ADJUSTMENT FACTOR	1.001475
FACTOR ADJUSTED FOR REG FEE =	$\frac{\$17,578,384}{4,013,280,667}$ x 1.001475	
FACTOR (Incl. Reg Fee) =	$0.004386 / KWH (D)	

NOTES

(A) FROM COMPANY EXHIBIT AJM-1 SCHEDULE 2

(B) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 2, PAGE 2

(C) WITHOUT NC REGULATORY FEE $0.004380 /KWH

(D) WITH NC REGULATORY FEE $0.004386 /KWH

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF EXPERIENCE MODIFICATION FACTOR - RIDER B
TWELVE MONTHS ENDED JUNE 30, 2023
TO BE EFFECTIVE FEBRUARY 1, 2024

CUSTOMER CLASS	(1) KWH SALES (A)	(2) NC JURISDICTIONAL EMF EXCLUDING REGULATORY FEE (B)	(3) FUEL REVENUE UNIFORM EMF EXCLUDING REGULATORY FEE (1) x (2)
RESIDENTIAL	1,577,823,651	$0.004380	$6,910,952
SGS & PA	762,250,648	$0.004380	$3,338,699
LGS	631,266,126	$0.004380	$2,764,979
SCHEDULE NS	733,864,312	$0.004380	$3,214,365
6VP	284,558,909	$0.004380	$1,246,383
OUTDOOR LIGHTING	23,121,607	$0.004380	$101,274
TRAFFIC	395,414	$0.004380	$1,732
TOTAL	4,013,280,667		$17,578,384

CUSTOMER CLASS	(1) KWH SALES (A)	(2) NC JURISDICTIONAL EMF INCLUDING REGULATORY FEE (B)	(3) FUEL REVENUE UNIFORM EMF INCLUDING REGULATORY FEE (1) x (2)	(4) CLASS EXPANSION FACTOR	(5) CLASS KWH @ GENERATION LEVEL (1) x (4)	(6) UNIFORM EMF @ GENERATION LEVEL (3a) / (5a)	(7) VOLTAGE DIFFERENTIATED EMF @ SALES LEVEL (4) x (6)
RESIDENTIAL	1,577,823,651	$0.004386	$6,920,335	1.053586	1,662,372,909	$0.004206	$0.004431
SGS & PA	762,250,648	$0.004386	$3,343,231	1.052612	802,354,179	$0.004206	$0.004427
LGS	631,266,126	$0.004386	$2,768,733	1.045160	659,774,105	$0.004206	$0.004396
SCHEDULE NS	733,864,312	$0.004386	$3,218,729	1.012814	743,268,049	$0.004206	$0.004260
6VP	284,558,909	$0.004386	$1,248,075	1.027402	292,356,392	$0.004206	$0.004321
OUTDOOR LIGHTING	23,121,607	$0.004386	$101,411	1.053586	24,360,601	$0.004206	$0.004431
TRAFFIC	395,414	$0.004386	$1,734	1.053586	416,603	$0.004206	$0.004431
TOTAL	4,013,280,667		$17,602,249 (3a)		4,184,902,838 (5a)		

NOTES

(A) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 2, PAGE 2

(B) IN $/KWH

PRIOR PERIOD FUEL EXPENSE RECOVERY ESTIMATE
JULY 2023 THROUGH JANUARY 2024

2023-2024	(1) FORECASTED NORTH CAROLINA JURISDICTION KWH SALES (A)	(2) PRIOR PERIOD FUEL FACTOR RIDER B (B)	(3) NORTH CAROLINA JURISDICTION PRIOR PD. RECOVERY	(4) CUMULATIVE PRIOR PD. RECOVERY
JULY 31, 2023 EMF BALANCE: (C)				$ 57,414,755
AUGUST 2023	341,316,531	$ 0.015976	$ 5,452,873	$ 51,961,882
SEPTEMBER 2023	329,709,198	$ 0.015976	$ 5,267,434	$ 46,694,448
OCTOBER 2023	297,413,541	$ 0.015976	$ 4,751,479	$ 41,942,969
NOVEMBER 2023	310,397,394	$ 0.015976	$ 4,958,909	$ 36,984,060
DECEMBER 2023	359,609,744	$ 0.015976	$ 5,745,125	$ 31,238,935
JANUARY 2024	287,953,467	$ 0.015976	$ 4,600,345	$ 26,638,591
TOTAL	1,926,399,875			

( ) Denotes Over-Recovery
(A) Monthly kWh sales information from the Company's internal forecast
(B) Jurisdictional Rider B Rate Level August 1, 2023 - January 31, 2024.
(C) The July 31, 2023 EMF Balance is derived from rate year revenue presented in Company Exhibit AJM-1 Schedule 4 and the approved August 31, 2022 EMF balance of $66,729,993

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF EXPERIENCE MODIFICATION FACTOR - RIDER B1
PROJECTED REMAINDER OF JULY 1, 2021 - AUGUST 31, 2022 NC JURISDICTIONAL
TO BE EFFECTIVE FEBRUARY 1, 2024

EXPENSE:	PROJECTED REMAINDER OF JULY 1, 2021 - AUGUST 31, 2022 NC JURISDICTIONAL FUEL EXPENSE UNDER RECOVERY (A)	$26,638,591
INTEREST:		$0
NET:		$26,638,591
SALES:	12 MONTHS JURISDICTIONAL KWH SALES ADJUSTED FOR CHANGE IN USAGE, WEATHER, AND CUSTOMER GROWTH (B)	4,013,280,667
FACTOR (Excl. Reg Fee) =	$0.006638 / KWH (C)	
FEE:	NORTH CAROLINA REGULATORY FEE ADJUSTMENT FACTOR	1.001475

FACTOR ADJUSTED FOR REG FEE = $\frac{\$26,638,591}{4,013,280,667}$ x 1.001475

FACTOR (Incl. Reg Fee) = $0.006648 / KWH (D)

NOTES

(A) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 4

(B) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 2, PAGE 2

(C) WITHOUT NC REGULATORY FEE $0.006638 /KWH

(D) WITH NC REGULATORY FEE $0.006648 /KWH

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF EXPERIENCE MODIFICATION FACTOR - RIDER B1
PROJECTED REMAINDER OF JULY 1, 2021 - AUGUST 31, 2022 NC JURISDICTIONAL
TO BE EFFECTIVE FEBRUARY 1, 2024

	(1)	(2)	(3)
CUSTOMER CLASS	KWH SALES (A)	NC JURISDICTIONAL EMF EXCLUDING REGULATORY FEE (B)	FUEL REVENUE UNIFORM EMF EXCLUDING REGULATORY FEE (1) x (2)
RESIDENTIAL	1,577,823,651	$0.006638	$10,472,978
SGS & PA	762,250,648	$0.006638	$5,059,522
LGS	631,266,126	$0.006638	$4,190,098
SCHEDULE NS	733,864,312	$0.006638	$4,871,105
6VP	284,558,909	$0.006638	$1,888,791
OUTDOOR LIGHTING	23,121,607	$0.006638	$153,472
TRAFFIC	395,414	$0.006638	$2,625
TOTAL	4,013,280,667		$26,638,591

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
CUSTOMER CLASS	KWH SALES (A)	NC JURISDICTIONAL B1 EMF INCLUDING REGULATORY FEE (B)	FUEL REVENUE UNIFORM B1 EMF INCLUDING REGULATORY FEE (1) x (2)	CLASS EXPANSION FACTOR	CLASS KWH @ GENERATION LEVEL (1) x (4)	UNIFORM B1 EMF @ GENERATION LEVEL (3a) / (5a)	VOLTAGE DIFFERENTIATED B1 EMF @ SALES LEVEL (4) x (6)
RESIDENTIAL	1,577,823,651	$0.006648	$10,489,372	1.053586	1,662,372,909	$0.006375	$0.006717
SGS & PA	762,250,648	$0.006648	$5,067,442	1.052612	802,354,179	$0.006375	$0.006710
LGS	631,266,126	$0.006648	$4,196,657	1.045160	659,774,105	$0.006375	$0.006663
SCHEDULE NS	733,864,312	$0.006648	$4,878,730	1.012814	743,268,049	$0.006375	$0.006457
6VP	284,558,909	$0.006648	$1,891,748	1.027402	292,356,392	$0.006375	$0.006550
OUTDOOR LIGHTING	23,121,607	$0.006648	$153,712	1.053586	24,360,601	$0.006375	$0.006717
TRAFFIC	395,414	$0.006648	$2,629	1.053586	416,603	$0.006375	$0.006717
TOTAL	4,013,280,667		$26,680,290 (3a)		4,184,902,838 (5a)		

NOTES

(A) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 2, PAGE 2

(B) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 5, PAGE 1

DOMINION ENERGY NORTH CAROLINA
TOTAL FUEL COST LEVEL - PRESENT AND PROPOSED
TO BE EFFECTIVE FEBRUARY 1, 2024

	(1)	(2)	(3)	(4)	(5)
NC JURISDICTION	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.020920	$0.009791	$0.015976	$0.000000	$0.046687
PROPOSED	$0.020920	$0.013655	$0.004386	$0.006648	$0.045609
CHANGE	$0.000000	$0.003864	($0.011590)	$0.006648	($0.001078)
RESIDENTIAL	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.021180	$0.009861	$0.016147	$0.000000	$0.047188
PROPOSED	$0.021180	$0.013754	$0.004431	$0.006717	$0.046082
CHANGE	$0.000000	$0.003893	($0.011716)	$0.006717	($0.001106)
SGS & PA	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.021150	$0.009849	$0.016126	$0.000000	$0.047125
PROPOSED	$0.021150	$0.013751	$0.004427	$0.006710	$0.046038
CHANGE	$0.000000	$0.003902	($0.011699)	$0.006710	($0.001087)
LGS	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.020980	$0.009792	$0.016008	$0.000000	$0.046780
PROPOSED	$0.020980	$0.013674	$0.004396	$0.006663	$0.045713
CHANGE	$0.000000	$0.003882	($0.011612)	$0.006663	($0.001067)

NOTES

( ) DENOTES NEGATIVE VALUE

DOMINION ENERGY NORTH CAROLINA
TOTAL FUEL COST LEVEL - PRESENT AND PROPOSED
TO BE EFFECTIVE FEBRUARY 1, 2024

	(1)	(2)	(3)	(4)	(5)
SCHEDULE NS	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.020360	$0.009482	$0.015524	$0.000000	$0.045366
PROPOSED	$0.020360	$0.013222	$0.004260	$0.006457	$0.044299
CHANGE	$0.000000	$0.003740	($0.011264)	$0.006457	($0.001067)
6VP	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.020650	$0.009621	$0.015747	$0.000000	$0.046018
PROPOSED	$0.020650	$0.013416	$0.004321	$0.006550	$0.044937
CHANGE	$0.000000	$0.003795	($0.011426)	$0.006550	($0.001081)
OUTDOOR LIGHTING	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.021180	$0.009861	$0.016147	$0.000000	$0.047188
PROPOSED	$0.021180	$0.013754	$0.004431	$0.006717	$0.046082
CHANGE	$0.000000	$0.003893	($0.011716)	$0.006717	($0.001106)
TRAFFIC	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.021180	$0.009861	$0.016147	$0.000000	$0.047188
PROPOSED	$0.021180	$0.013754	$0.004431	$0.006717	$0.046082
CHANGE	$0.000000	$0.003893	($0.011716)	$0.006717	($0.001106)

NOTES

( ) DENOTES NEGATIVE VALUE

DOMINION ENERGY NORTH CAROLINA
TOTAL FUEL RECOVERY
TWELVE MONTHS ENDED JUNE 30, 2023
TO BE EFFECTIVE FEBRUARY 1, 2024

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
CUSTOMER CLASS	SALES(KWH)	BASE FUEL COMPONENT (A)	FUEL COST RIDER A (B)	EMF RIDER B (C)	EMF RIDER B1 (D)	TOTAL (2) + (3) + (4) + (5)	TOTAL REVENUE (1) x (6)
RESIDENTIAL	1,577,823,651	$0.021180	$0.013754	$0.004431	$0.006717	$0.046082	$72,709,269
SGS & PA	762,250,648	$0.021150	$0.013751	$0.004427	$0.006710	$0.046038	$35,092,495
LGS	631,266,126	$0.020980	$0.013674	$0.004396	$0.006663	$0.045713	$28,857,068
SCHEDULE NS	733,864,312	$0.020360	$0.013222	$0.004260	$0.006457	$0.044299	$32,509,455
6VP	284,558,909	$0.020650	$0.013416	$0.004321	$0.006550	$0.044937	$12,787,224
OUTDOOR LIGHTING	23,121,607	$0.021180	$0.013754	$0.004431	$0.006717	$0.046082	$1,065,490
TRAFFIC	395,414	$0.021180	$0.013754	$0.004431	$0.006717	$0.046082	$18,221
TOTAL	4,013,280,667						$183,039,223

	SALES(KWH)	BASE FUEL COMPONENT	FUEL COST RIDER A	EMF RIDER B	EMF RIDER B1	TOTAL (2) + (3) + (4) + (5)	TOTAL REVENUE (1) x (6)
NORTH CAROLINA JURISDICTION	4,013,280,667	$0.020920	$0.013655	$0.004386	$0.006648	$0.045609	$183,041,718

	SALES(KWH)	PRESENT TOTAL RATE	PROPOSED TOTAL RATE	TOTAL CHANGE (3) - (2)	TOTAL REVENUE CHANGE (4) x (1)
NORTH CAROLINA JURISDICTION REVENUE CHANGE	4,013,280,667	$0.046687	$0.045609	($0.001078)	($4,326,317)

NOTES

(A) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 2, PAGE 2

(B) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 2, PAGE 2

(C) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 3, PAGE 2

(D) FROM COMPANY EXHIBIT TPS-1 SCHEDULE 5, PAGE 2

RIDER A

FUEL COST RIDER

The applicable cents per kilowatt-hour charge[1] shall be added to the base fuel cost contained in the energy charges within each of the following Dominion Energy North Carolina filed Rate Schedules.

Rate Schedule	Customer Class	Cents per kWh Charge
Schedule 1	Residential	1.3754¢/kWh
Schedule 1DF	Residential	1.3754¢/kWh
Schedule 1P	Residential	1.3754¢/kWh
Schedule 1T	Residential	1.3754¢/kWh
Schedule 1W	Residential	1.3754¢/kWh
Schedule 5	SGS & Public Authority	1.3751¢/kWh
Schedule 5C	SGS & Public Authority	1.3751¢/kWh
Schedule 5P	SGS & Public Authority	1.3751¢/kWh
Schedule 7	SGS & Public Authority	1.3751¢/kWh
Schedule 30	SGS & Public Authority	1.3751¢/kWh
Schedule 42	SGS & Public Authority	1.3751¢/kWh
Schedule 6C	Large General Service	1.3674¢/kWh
Schedule 6L	Large General Service	1.3674¢/kWh
Schedule 6P	Large General Service	1.3674¢/kWh
Schedule 10	Large General Service	1.3674¢/kWh
Schedule LGS – RTP With Customer Baseline Load	Large General Service	1.3674¢/kWh
Schedule 26	Outdoor Lighting	1.3754¢/kWh
Schedule 30T	Traffic Control	1.3754¢/kWh
Schedule 6VP	6VP	1.3416¢/kWh
Schedule NS Tier 2-Type A and Tier 3 Energy Charges	Schedule NS	1.3222¢/kWh
Schedule NS Tier 1 Type A & B, and Tier 2-Type B Energy Charges	Schedule NS	Rider A is Included in the Energy Charges

[1]This charge is not a part of the base fuel cost included in the energy prices stated in the Rate Schedules and should, therefore, be applied in addition to the prices stated in the Rate Schedules.

RIDER B

EXPERIENCE MODIFICATION FACTOR (EMF)

The applicable cents per kilowatt-hour charge[1] shall be added to the energy charges contained within each of the following Dominion Energy North Carolina filed Rate Schedules.

Rate Schedule	Customer Class	Cents per kWh Charge
Schedule 1	Residential	0.4431¢/kWh
Schedule 1DF	Residential	0.4431¢/kWh
Schedule 1P	Residential	0.4431¢/kWh
Schedule 1T	Residential	0.4431¢/kWh
Schedule 1W	Residential	0.4431¢/kWh
Schedule 5	SGS & Public Authority	0.4427¢/kWh
Schedule 5C	SGS & Public Authority	0.4427¢/kWh
Schedule 5P	SGS & Public Authority	0.4427¢/kWh
Schedule 7	SGS & Public Authority	0.4427¢/kWh
Schedule 30	SGS & Public Authority	0.4427¢/kWh
Schedule 42	SGS & Public Authority	0.4427¢/kWh
Schedule 6C	Large General Service	0.4396¢/kWh
Schedule 6L	Large General Service	0.4396¢/kWh
Schedule 6P	Large General Service	0.4396¢/kWh
Schedule 10	Large General Service	0.4396¢/kWh
Schedule LGS – RTP With Customer Baseline Load	Large General Service	0.4396¢/kWh
Schedule 26	Outdoor Lighting	0.4431¢/kWh
Schedule 30T	Traffic Control	0.4431¢/kWh
Schedule 6VP	6VP	0.4321¢/kWh
Schedule NS Tier 2-Type A and Tier 3 Energy Charges	Schedule NS	0.4260¢/kWh
Schedule NS Tier 1 Type A & B, and Tier 2-Type B Energy Charges	Schedule NS	Rider B is Included in the Energy Charges

[1]This charge is not a part of the base fuel cost included in the energy prices stated in the Rate Schedules and should, therefore, be applied in addition to the prices stated in the Rate Schedules.

RIDER B1

EXPERIENCE MODIFICATION FACTOR (EMF)

The applicable cents per kilowatt-hour charge[1] shall be added to the energy charges contained within each of the following Dominion Energy North Carolina filed Rate Schedules.

Rate Schedule	Customer Class	Cents per kWh Charge
Schedule 1	Residential	0.6717¢/kWh
Schedule 1DF	Residential	0.6717¢/kWh
Schedule 1P	Residential	0.6717¢/kWh
Schedule 1T	Residential	0.6717¢/kWh
Schedule 1W	Residential	0.6717¢/kWh
Schedule 5	SGS & Public Authority	0.6710¢/kWh
Schedule 5C	SGS & Public Authority	0.6710¢/kWh
Schedule 5P	SGS & Public Authority	0.6710¢/kWh
Schedule 7	SGS & Public Authority	0.6710¢/kWh
Schedule 30	SGS & Public Authority	0.6710¢/kWh
Schedule 42	SGS & Public Authority	0.6710¢/kWh
Schedule 6C	Large General Service	0.6663¢/kWh
Schedule 6L	Large General Service	0.6663¢/kWh
Schedule 6P	Large General Service	0.6663¢/kWh
Schedule 10	Large General Service	0.6663¢/kWh
Schedule LGS – RTP With Customer Baseline Load	Large General Service	0.6663¢/kWh
Schedule 26	Outdoor Lighting	0.6717¢/kWh
Schedule 30T	Traffic Control	0.6717¢/kWh
Schedule 6VP	6VP	0.6550¢/kWh
Schedule NS Tier 2-Type A and Tier 3 Energy Charges	Schedule NS	0.6457¢/kWh
Schedule NS Tier 1 Type A & B, and Tier 2-Type B Energy Charges	Schedule NS	Rider B1 is Included in the Energy Charges

[1]This charge is not a part of the base fuel cost included in the energy prices stated in the Rate Schedules and should, therefore, be applied in addition to the prices stated in the Rate Schedules.