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August 11, 2020

**VIA ELECTRONIC FILING**

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

*Re: Dominion Energy North Carolina's 2020 Fuel Charge Adjustment*
*Docket No. E-22, Sub 590*

Dear Ms. Campbell:

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, Ronnie T. Campbell, Dale E. Hinson, Tom A. Brookmire, and George G. Beasley, 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:sjg

Enclosures

cc: Lucy Edmondson
Dianna Downey

# 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 590**

**Filed: August 11, 2020**

**STATE OF NORTH CAROLINA**
**UTILITIES COMMISSION**
**RALEIGH**

DOCKET NO. E-22, SUB 590

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, 2021, and remain in effect through January 31, 2022. 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 120,000 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, Ronnie T. Campbell, Dale E. Hinson, Tom A. Brookmire, and George G. Beasley.

4. Pursuant to Rule R8-55(c), DENC's test period for this proceeding is the 12-month period ending June 30, 2020 ("Test Period").

5. The Commission's last fuel adjustment proceeding order for the Company was issued on January 23, 2020, in Docket No. E-22, Sub 579 ("2019 Fuel Order"). The 2019 Fuel Order approved the current Rider A of zero and an updated Experience Modification Factor ("EMF") Rider B of $0.00013. 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, and consistent with the 2019 Fuel 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 2019 Base Rate Case Order and the 2019 Fuel Order also set the marketer's percentage at 71% (to be reviewed during the Company's 2021 fuel factor filing or during the Company's next general rate case, whichever comes first).

6. 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, 2021 through January 31, 2022 Rate Period.

7. For the Test Period, the normalized system fuel expense is $1,568,811,597, which is then divided by system sales of 85,444,348,726 kWh, which reflect the normalization adjustments for change in usage, weather, and customer growth.

The result is a normalized system average fuel factor of $0.01838/ kWh, which is a decrease of 0.00254 ¢/kWh, applicable to the North Carolina jurisdiction.

8. DENC has over-recovered its fuel costs for the Test Period by $4,049,129. The total over-recovered fuel expense as of June 30, 2020, based on the current 71% marketer percentage, is provided in the direct testimony and exhibits of Company Witness Ronnie T. Campbell. This fuel over-recovery was primarily driven by moderate winter weather and the absence of major spikes or movements in commodity prices.

9. The Company calculated the EMF Rider B, including interest, applicable to the North Carolina jurisdiction and to each customer class using the methodology approved in the 2019 Fuel Order. These calculations are addressed in the direct testimony and exhibits of Company Witness George G. Beasley.

10. The Company proposes that the total fuel rate (base fuel factor, Rider A, and EMF Rider B) for each class be set as follows, effective February 1, 2021:

| Customer Class | Total |
|---|---|
| Residential | $0.01737 |
| SGS & PA | $0.01735 |
| LGS | $0.01722 |
| Schedule NS | $0.01694 |
| 6VP | $0.01671 |
| Outdoor Lighting | $0.01737 |
| Traffic | $0.01737 |

11. For the North Carolina jurisdiction, the proposed jurisdictional fuel cost levels result in a total fuel recovery decrease of $15,418,104.

WHEREFORE, Dominion Energy North Carolina respectfully requests that the Commission: approve the proposed total fuel factor of 1.721 ¢/kWh, effective February 1, 2021, which shall be allocated based on voltage differentiated adjustments, including the base fuel factor, Rider A, and EMF Rider B, as follows:

(a) 1.737 ¢/kWh for the Residential class of customers,
(b) 1.735 ¢/kWh for the Small General Service and Public Authority classes of customers,
(c) 1.722 ¢/kWh for the Large General Service class of customers,
(d) 1.694 ¢/kWh for the Schedule NS class of customers,
(e) 1.671 ¢/kWh for the Schedule 6VP class of customers, and
(f) 1.737 ¢/kWh for the Outdoor Lighting and Traffic classes of customers;

and grant any other relief the Commission deems appropriate.

Respectfully submitted, this the 11th day of August, 2020.

DOMINION ENERGY NORTH CAROLINA

By: */s/Mary Lynne Grigg*
Counsel

*Counsel for Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina*

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**DIRECT TESTIMONY OF**
**JEFFREY D. MATZEN**
**ON BEHALF OF**
**DOMINION ENERGY NORTH CAROLINA**
**BEFORE THE**
**NORTH CAROLINA UTILITIES COMMISSION**

**DOCKET NO. E-22, SUB 590**

**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, 2020 ("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 2021 through January 2022.

**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, 2020 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 7,150 GWh of energy. Mt. Storm Units 1-3 performed at EA factors of 78.4%, 73.7%, and 58.5%, respectively. Chesterfield Units 5 – 6 had EA factors of 60.7% and 68.7%, respectively. Virginia City Hybrid Energy Center ("VCHEC") had an EA of 65.2% during the Test Period.

In regards to what constitutes reasonable nuclear unit performance, Commission Rule R8-55(k) requires that the Company's actual system-wide nuclear capacity factor in the Test Period must exceed the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected by the North American Electric Reliability Corporation ("NERC"), appropriately weighted for size and type of plant. The NERC 2014-2018 five-year industry average net capacity factor for Pressurized Water Reactors, which is the most recent available NERC average, is 92.2% for 800-999 MW units. The net capacity factors during the historic Test Period for the Company's nuclear units are shown below.

| | |
|---|---|
| N. Anna 1 | 95.0% |
| N. Anna 2 | 99.2% |
| Surry 1 | 90.3 % |
| Surry 2 | 92.6% |

The aggregate capacity factor was 94.3 % 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 performance during the Test Period was clearly better than the industry five-year average for comparable units.

In addition, for the same five-year period, the Company's net capacity factor was 94.3% compared to the national average of 92.2%. Nuclear net capacity factor is the best measure for reliable baseload performance and related operating efficiency and is the predominant standard recognized 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.

**Q. What is the expected performance of the Company's nuclear generating units for the 12-month rate period ending January 31, 2022?**

A. The projected capacity factors for both North Anna and Surry are expected to be above the most recent NERC five-year average capacity factor of 92.2%. The projected capacity factors are shown below.

| | |
|---|---|
| N. Anna 1 | 90.6% |
| N. Anna 2 | 90.6 % |
| Surry 1 | 92.8% |
| Surry 2 | 100.2% |

The projected weighted average for the nuclear fleet at ownership is 93.4%.

**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 31.3%; coal-fired generation supplied 8.1%; combined cycle and combustion turbine generation supplied 47.1%; and power transactions (net) supplied 11.9%. These four energy sources accounted for 98.4% of the total energy supply. Oil, biomass, solar and hydro generation provided the remaining 1.6% (net) of the energy supplied.

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

A. As stated by Company Witness Ronnie T. Campbell, the Company experienced a small over-recovery of fuel expenses during the test year. This minor fuel over-recovery was primarily driven by moderate winter weather and no major commodity price spikes and a general downward movement in all commodity prices.

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

A. Yes. The Company's projected nuclear generation during the upcoming rate year is expected to be slightly lower 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, 2022, 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 2022. Other sources of generation were then normalized for the Test Period. The total of coal, heavy oil, combustion turbine and combined cycle, non-utility generation ("NUG"), 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 generation. This methodology for normalizing the Test Period generation resulted in adjusted annual system energy requirements of 86,192,004 MWh, a decrease of 2,512,113 MWhs from the actual energy requirements for the 12 months ended June 30, 2020.

**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 142 MW (nominal alternating current ("AC")) Colonial Trail West Solar Facility was brought online in December 2019. The Spring Grove Solar Facility, an approximately 135 MW (nominal alternating current ("AC")) facility located in Surry County, is expected to be in service later in 2020. The Company is planning on retiring Possum Point Unit 5 in June 2021. This unit is fueled by #6 oil and would require a large expenditure on environmental equipment in order to remain in compliance. The Company does not anticipate a significant impact to system fuel expense from any of these changes.

**Q. Please describe the other fuel expense normalization items.**

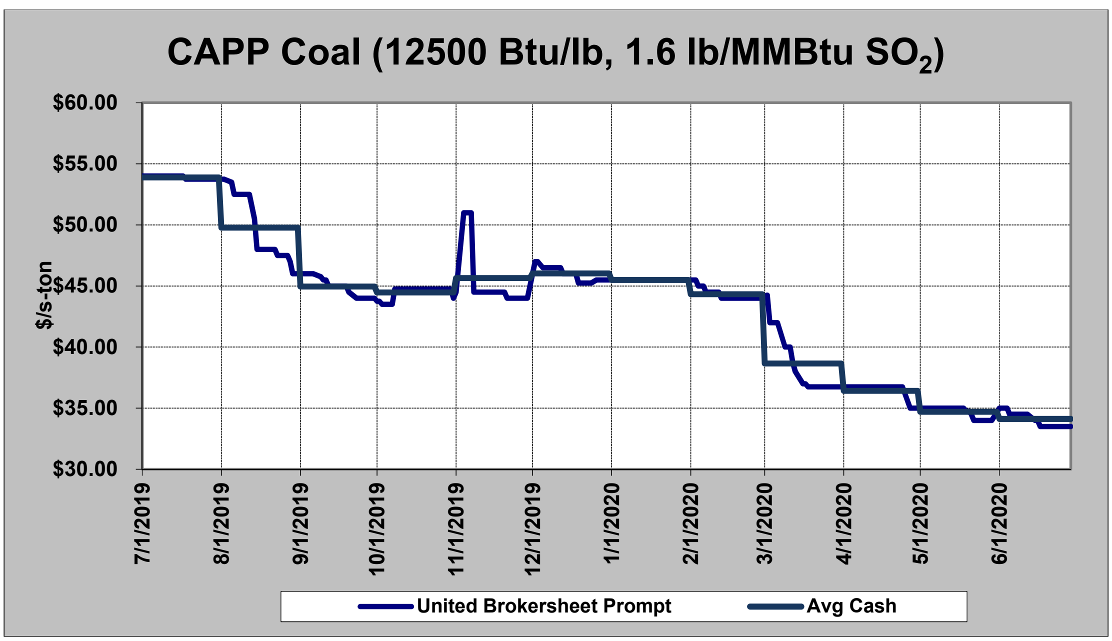
**A**. The $/MWh expense rates for all fuel types are based on the actual 12-month average expense rates incurred during the Test Period. Using the 12-month average rate for these commodities is consistent with the methodology used in the 2008 – 2019 fuel cases and is a fair representation of the expected expense rates during the February 2021 – January 2022 rate period.

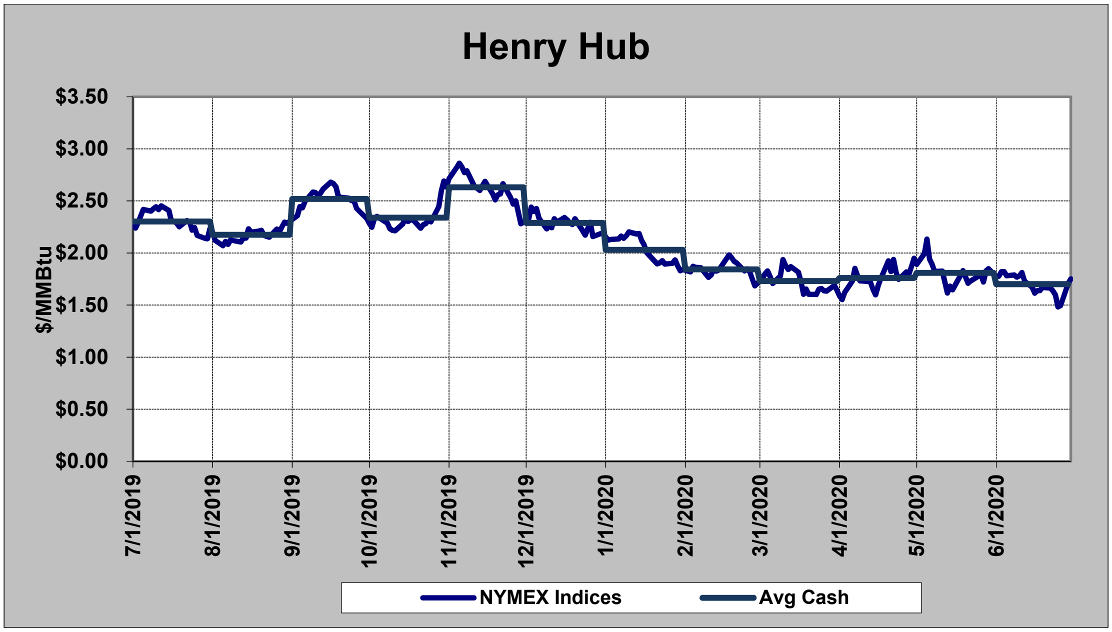
**Q. What is the resulting normalized system fuel expense?**

A. As shown by Schedule 4, which also presents the detailed calculations in support, the resulting normalized system fuel expense is approximately $1.57 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 substantially during the Test Period. Company Witness Dale E. 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 declined and have shown some volatility during the Test Period.




Henry Hub
$/MMBtu
$3.50
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
7/1/2019
8/1/2019
9/1/2019
10/1/2019
11/1/2019
12/1/2019
1/1/2020
2/1/2020
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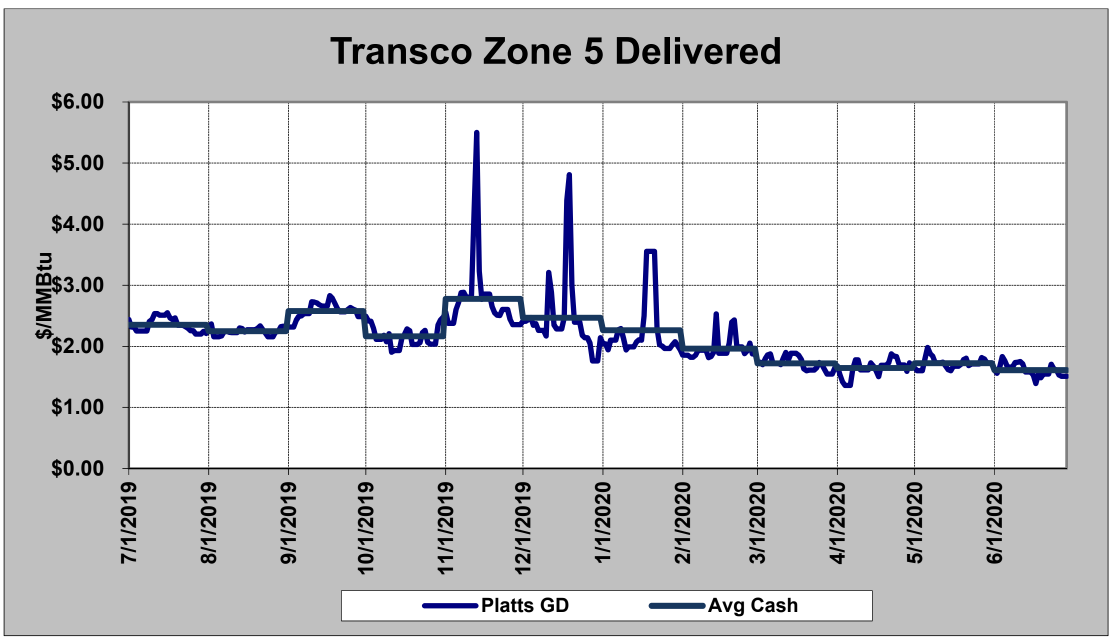
6/1/2020
NYMEX Indices
Avg Cash


Transco Zone 5 Delivered
$/MMBtu
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
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8/1/2019
9/1/2019
10/1/2019
11/1/2019
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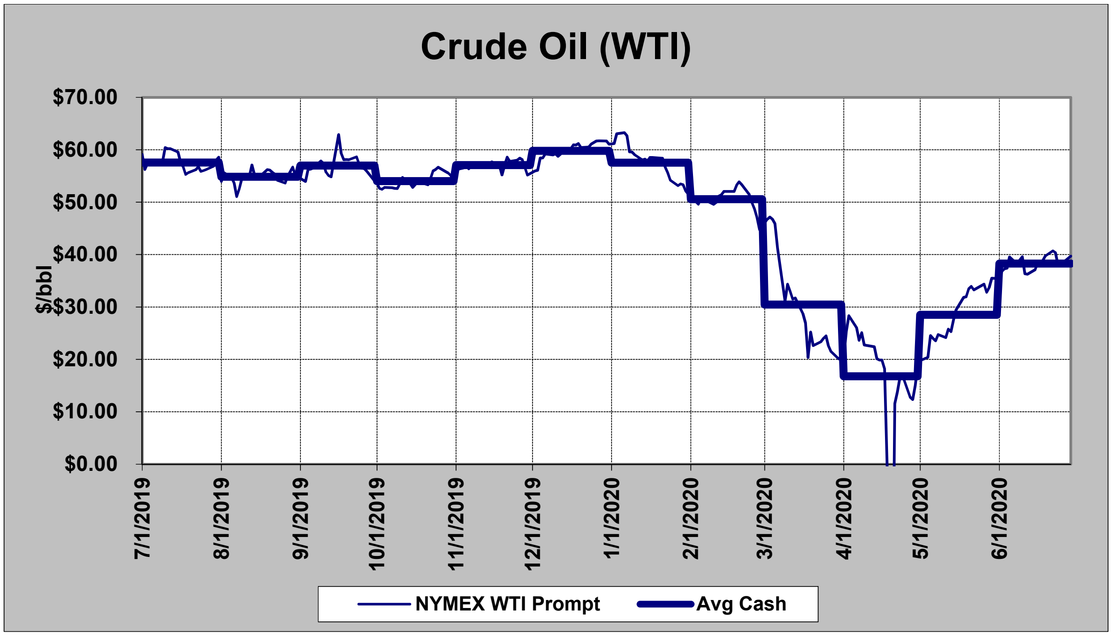
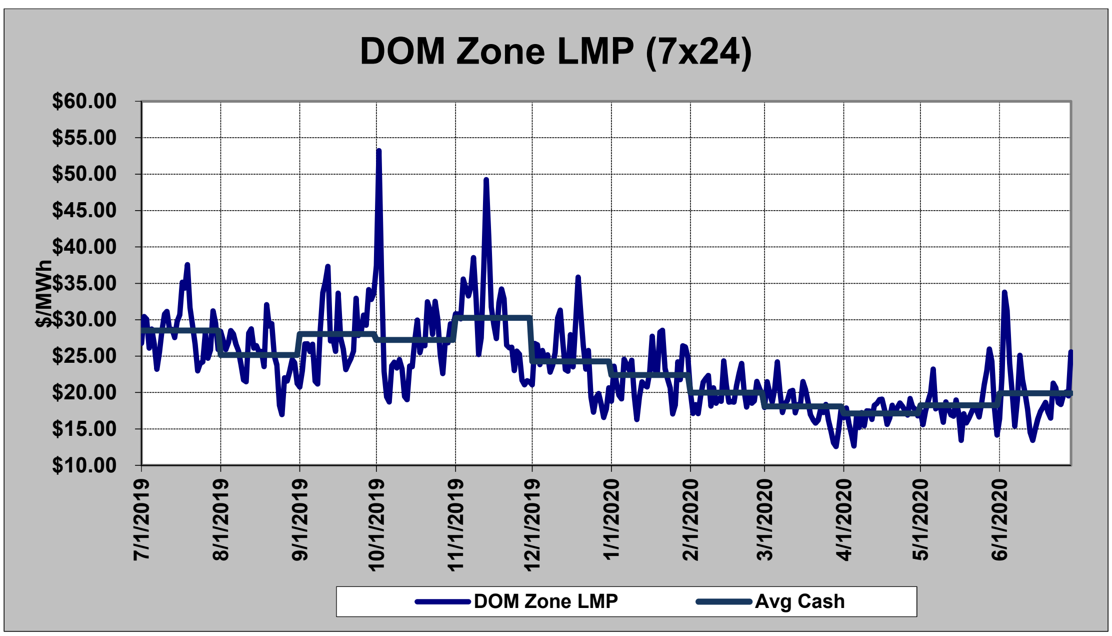
6/1/2020
Platts GD
Avg Cash




**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.

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

**July 2019-June 2020**

| | 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-19 | 100.0% | 100.0% | 100.0% | 100.0% | 93.4% | 81.2% | 99.8% | 36.4% | 98.8% | 76.6% |
| Aug-19 | 100.0% | 100.0% | 100.0% | 100.0% | 98.9% | 68.7% | 54.8% | 87.8% | 100.0% | 64.2% |
| Sep-19 | 23.2% | 100.0% | 100.0% | 100.0% | 78.1% | 77.9% | 15.0% | 40.0% | 40.0% | 40.0% |
| Oct-19 | 98.9% | 100.0% | 58.0% | 100.0% | 71.8% | 83.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Nov-19 | 100.0% | 100.0% | 3.7% | 100.0% | 54.8% | 98.9% | 67.2% | 0.0% | 0.0% | 19.7% |
| Dec-19 | 100.0% | 100.0% | 100.0% | 100.0% | 98.8% | 12.0% | 0.0% | 32.4% | 80.9% | 100.0% |
| Jan-20 | 100.0% | 99.8% | 100.0% | 100.0% | 53.4% | 87.8% | 84.0% | 89.3% | 99.9% | 86.8% |
| Feb-20 | 100.0% | 99.1% | 100.0% | 100.0% | 61.2% | 64.0% | 72.3% | 100.0% | 100.0% | 63.8% |
| Mar-20 | 98.8% | 100.0% | 100.0% | 100.0% | 85.4% | 98.4% | 100.0% | 100.0% | 100.0% | 100.0% |
| Apr-20 | 100.0% | 69.6% | 100.0% | 97.5% | 95.0% | 56.7% | 100.0% | 100.0% | 100.0% | 98.5% |
| May-20 | 99.8% | 94.6% | 100.0% | 99.5% | 50.8% | 75.5% | 44.2% | 51.6% | 93.5% | 62.8% |
| Jun-20 | 97.7% | 100.0% | 100.0% | 100.0% | 99.1% | 80.0% | 64.6% | 91.0% | 11.0% | 69.9% |
| 12-Month Average | 93.3% | 97.0% | 88.5% | 99.8% | 78.4% | 73.7% | 58.5% | 60.7% | 68.7% | 65.2% |

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

**July 2019-June 2020**

| | 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-19 | 99.6% | 99.5% | 100.2% | 100.1% | 61.6% | 55.9% | 56.6% | 0.0% | 32.9% | 45.8% |
| Aug-19 | 100.1% | 100.4% | 101.0% | 100.8% | 51.0% | 25.3% | 0.0% | 21.0% | 29.4% | 29.9% |
| Sep-19 | 23.1% | 101.4% | 101.6% | 101.6% | 32.3% | 30.3% | 0.0% | 12.8% | 12.2% | 18.2% |
| Oct-19 | 97.8% | 102.7% | 58.7% | 103.4% | 42.6% | 51.5% | 0.0% | 0.0% | 0.0% | 0.0% |
| Nov-19 | 103.4% | 103.6% | 1.1% | 104.3% | 44.8% | 82.4% | 50.4% | 0.0% | 0.0% | 6.8% |
| Dec-19 | 103.4% | 103.5% | 102.8% | 104.2% | 71.2% | 0.1% | 0.0% | 0.0% | 0.0% | 5.0% |
| Jan-20 | 103.3% | 103.2% | 104.1% | 104.1% | 37.0% | 58.1% | 21.2% | 3.4% | 18.7% | 22.5% |
| Feb-20 | 103.3% | 102.1% | 103.7% | 103.4% | 6.3% | 24.2% | 29.8% | 0.0% | 0.0% | 33.3% |
| Mar-20 | 101.0% | 103.1% | 103.2% | 103.6% | 36.9% | 48.9% | 0.0% | 0.0% | 0.0% | 22.6% |
| Apr-20 | 102.8% | 71.1% | 102.5% | 94.9% | 57.5% | 0.0% | 4.8% | 0.0% | 0.0% | 24.5% |
| May-20 | 102.4% | 97.5% | 103.2% | 5.1% | 30.3% | 43.9% | 35.5% | 0.0% | 0.0% | 0.0% |
| Jun-20 | 98.4% | 101.3% | 100.9% | 86.9% | 72.1% | 57.9% | 48.0% | 33.9% | 3.9% | 0.0% |
| 12-Month Average | 95.0% | 99.2% | 90.3% | 92.6% | 45.3% | 39.9% | 20.5% | 5.9% | 8.1% | 17.4% |

**DOMINION ENERGY NORTH CAROLINA**
**SYSTEM ENERGY SUPPLY**

**Actual 12-Month Ended June 2020**

| | Generation (MWhs) | % of Energy Supply |
|---|---|---|
| Nuclear | 27,724,152 | 31.3% |
| Coal | 7,149,876 | 8.1% |
| Heavy Oil | 87,868 | 0.1% |
| Wood | 893,933 | 1.0% |
| Combined Cycle and Combustion Turbine | 41,800,412 | 47.1% |
| Solar and Hydro - Conventional and Pumped Storage | 3,050,046 | 3.4% |
| Net Power Transactions | 10,581,660 | 11.9% |
| Less Energy for Pumping | (2,583,830) | -2.9% |
| Total System | 88,704,117 | 100.0% |
| | | |
| Nuclear, NG, Coal and Net Power Transactions | | 98.4% |

Dominion Energy North Carolina
Docket No. E-22, Sub 590

Company Exhibit JDM-1
Schedule 4

**DOMINION ENERGY NORTH CAROLINA**
**ENERGY AND FUEL EXPENSES**

**Normalized and Adjusted Energy and Fuel Expense based on Actual 12-Months Ended June 2020**
**(Company Ownership Only)**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 12-Months Ended June 2020 | | | | | | | June 2020 | | | |
| | Expense ($) | Generation (MWh) | Rate ($/MWh) | Supply (%) | Ratio of Coal Oil, CT & CC NUG & Other MWH To Total Sum | Coal, Oil, CT & CC, NUG, 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) | 268,434,982 | 8,043,809 | 33.37 | 9.1 | 0.1329 | 58,534,976 | 7,780,762 | 32,318,954 | 925,251 | 33.37 (4) | 259,644,028 |
| Nuclear | | | | | | | | | | | |
| Surry | 79,904,012 | 13,463,884 | 5.93 | 15.2 | | | 14,174,190 | 6,621,299 | 1,132,844 | | |
| North Anna | 86,725,002 | 14,260,268 | 6.08 | 16.1 | | | 13,271,090 | 7,301,996 | 1,202,264 | | |
| Total Nuclear | 166,629,015 (3) | 27,724,152 | 6.01 | 31.3 | | | 27,445,280 | 13,923,294 | 2,335,109 | 6.01 (4) | 164,946,133 |
| Heavy Oil | 6,580,634 | 87,868 | 74.89 | 0.1 | 0.0015 | 58,534,976 | 84,993 | 0 | 0 | 74.89 (4) | 6,365,126 |
| CC & CT (2) | 852,719,899 | 41,800,412 | 20.40 | 47.1 | 0.6908 | 58,534,976 | 40,433,562 | 58,213,961 | 3,750,131 | 20.40 (4) | 824,844,665 |
| Hydro | 0 | 2,795,636 | | 3.2 | | | 2,795,636 | 0 | 356,056 | | 0 |
| Solar | 0 | 254,410 | | 0.3 | | | 254,410 | | 47,584 | | |
| Power Transactions | | | | | | | | | | | |
| NUG Fuel | 129,756,589 | 2,221,419 | 58.41 | 2.5 | 0.0367 | 58,534,976 | 2,148,760 | 11,686,985 | 199,624 | 58.41 (4) | 125,512,462 |
| PJM Purchases | 193,838,157 | 8,360,241 | 23.19 | 9.4 | 0.1382 | 58,534,976 | 8,086,841 | (764,748) | 190,851 | 23.19 (5) | 187,499,183 |
| Net | 323,594,746 | 10,581,660 | 30.58 | 11.9 | | | 10,235,601 | 10,922,237 | 390,475 | | 313,011,645 |
| Pumping | 0 | (2,583,830) | | -2.9 | | | (2,583,830) | 0 | (264,446) | | 0 |
| Energy Supply | 1,617,959,276 | 88,704,117 | 18.24 | 100.0 | | | 86,192,004 | 115,378,446 | 7,540,159 | 18.20 at gen level | 1,568,811,597 |

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**
**RONNIE T. CAMPBELL**
**ON BEHALF OF**
**DOMINION ENERGY NORTH CAROLINA**
**BEFORE THE**
**NORTH CAROLINA UTILITIES COMMISSION**

**DOCKET NO. E-22, SUB 590**

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

A. My name is Ronnie T. Campbell, 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 ("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. Campbell, what is the purpose of your testimony in this proceeding?**

A. My testimony presents: 1) the Company's actual system fuel expenses for the twelve months ended June 30, 2020 ("test period"); 2) the Company's North Carolina recovery experience as of June 30, 2020; 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 RC-1 has been prepared under my direction and supervision and is accurate and complete to the best of my knowledge and belief. Exhibit RC-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, 2020.**

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 $1,617,959,276. The Company was in a fuel cost over-recovery position of $4,049,129 on a North Carolina jurisdictional basis as of June 30, 2020. Details regarding fuel expenses and the calculation of this over-recovery position, also referred to as the Experience Modification Factor ("EMF"), are provided in Exhibit RC-1 and are discussed later in my testimony.

**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 dispatachable 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 reasonable and prudent energy costs in the EMF calculation. Additionally, to the extent 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. Use of the 71% "marketer's percentage" was agreed to between the Company and the Public Staff and approved by the Commission in the Company's 2019 fuel factor proceeding, Docket No. E-22, Sub 579.

**Q. Please provide an explanation of the five schedules presented in Exhibit RC-1.**

A. Schedule 1, Column 1 presents the system fuel and purchased power expenses incurred by the Company during the test period totaling $1,645,952,067. Of that amount, $1,617,959,276 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. Nuclear (page 1 of Schedule 1)

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

2. Purchased Power (page 2 of Schedule 1)

   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 over-recovery of $4,049,129. 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 1 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.

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

A. The fuel costs allocated to North Carolina jurisdictional customers totaled $77,177,781. The Company received fuel revenues totaling $81,226,910. The difference between the fuel costs and the fuel revenues resulted in an over-recovery of $4,049,129 for the test period.

**Q. Please describe the information contained in Schedules 3 - 5 presented in Exhibit RC-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. 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. Campbell, does this conclude your direct testimony?**

A. Yes, it does.

**APPENDIX A**

## BACKGROUND AND QUALIFICATIONS OF Ronnie T. Campbell, CPA

Ronnie T. Campbell graduated from Virginia Tech with Bachelor of Science degree in Accounting. Mr. Campbell received his Certified Public Accountant license in 1998. He was controller at World Access Service Corporation (Allianz Global Assistance) prior to joining Dominion Energy Services, Inc. in 2007. His accounting experience includes retail, non-utility generation, petroleum and insurance industries. He has held several supervisor positions within the Dominion Energy Services, Inc. accounting organization, including contracted assets and non-fuel accounting. He transitioned into his current role in 2009. 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. Campbell has previously presented testimony before the North Carolina Utilities Commission.

# Dominion Energy North Carolina
## Actual System Fuel and Purchased Power Expenses
## July 2019 - June 2020

| | System Expenses As Booked (1) | North Carolina System Expenses As Booked (2) |
|---|---|---|
| **Steam Generation Fuel Cost** | | |
| July 2019 | $ 43,881,172 | $ 43,881,172 |
| August | 33,412,034 | 33,412,034 |
| September | 17,014,575 | 17,014,575 |
| October | 16,765,761 | 16,765,761 |
| November | 28,352,084 | 28,352,084 |
| December | 14,626,688 | 14,626,688 |
| January 2020 | 28,260,209 | 28,260,209 |
| February | 15,001,174 | 15,001,174 |
| March | 17,447,166 | 17,447,166 |
| April | 12,817,381 | 12,817,381 |
| May | 15,118,417 | 15,118,417 |
| June | 32,318,954 | 32,318,954 |
| FERC Account 501 - Steam Fuel Cost | $ 275,015,616 | $ 275,015,616 |
| **Nuclear Generation Fuel Cost** | | |
| July 2019 | $ 16,075,388 | $ 15,231,763 |
| August | 16,074,230 | 15,540,308 |
| September | 11,887,372 | 11,836,710 |
| October | 13,310,786 | 13,195,705 |
| November | 11,257,015 | 11,296,740 |
| December | 15,594,026 | 15,487,082 |
| January 2020 | 15,104,075 | 15,018,684 |
| February | 14,987,363 | 14,947,873 |
| March | 15,422,038 | 15,361,034 |
| April | 13,231,523 | 13,172,569 |
| May | 11,659,873 | 11,600,379 |
| June | 14,085,553 | 13,940,167 |
| FERC Account 518 - Nuclear Fuel Cost | $ 168,689,242 | $ 166,629,015 |

**Dominion Energy North Carolina**
**Actual System Fuel and Purchased Power Expenses**
**July 2019 - June 2020**

| | System Expenses As Booked (1) | North Carolina System Expenses As Booked (2) |
|---|---|---|
| **Other Generation Fuel Cost** | | |
| July 2019 | $ 86,424,812 | $ 86,424,812 |
| August | 78,153,990 | 78,153,990 |
| September | 68,865,844 | 68,865,844 |
| October | 35,248,705 | 35,248,705 |
| November | 50,692,530 | 50,692,530 |
| December | 100,938,742 | 100,938,742 |
| January 2020 | 108,644,107 | 108,644,107 |
| February | 99,014,725 | 99,014,725 |
| March | 65,998,788 | 65,998,788 |
| April | 49,105,343 | 49,105,343 |
| May | 51,414,855 | 51,414,855 |
| June | 58,217,458 | 58,217,458 |
| FERC Account 547 - Other Fuel Cost | $ 852,719,899 | $ 852,719,899 |
| Total Cost of Fuel Used in Current Generation | $ 1,296,424,757 | $ 1,294,364,530 |
| **Purchased Power** | | |
| July 2019 | 29,614,636 | $ 28,170,168 |
| August | 25,835,062 | 25,206,508 |
| September | 48,767,968 | 37,403,969 |
| October | 66,180,645 | 51,287,167 |
| November | 75,884,141 | 59,801,163 |
| December | 36,814,115 | 30,129,357 |
| January 2020 | 11,776,852 | 15,633,578 |
| February | 13,763,175 | 14,518,188 |
| March | 7,345,918 | 14,996,890 |
| April | 12,111,354 | 18,211,881 |
| May | 12,305,140 | 17,313,640 |
| June | 9,128,303 | 10,922,237 |
| FERC Account 555 - Purchased Power Cost | $ 349,527,309 | $ 323,594,746 |

## Dominion Energy North Carolina
## Actual System Fuel and Purchased Power Expenses
## July 2019 - June 2020

| | System Expenses As Booked (1) | North Carolina System Expenses As Booked (2) |
|---|---|---|
| **Total Fuel and Purchased Power Cost** | | |
| July 2019 | $ 175,996,008 | $ 173,707,916 |
| August | 153,475,317 | 152,312,841 |
| September | 146,535,758 | 135,121,097 |
| October | 131,505,897 | 116,497,339 |
| November | 166,185,771 | 150,142,518 |
| December | 167,973,570 | 161,181,869 |
| January 2020 | 163,785,244 | 167,556,578 |
| February | 142,766,437 | 143,481,960 |
| March | 106,213,910 | 113,803,878 |
| April | 87,265,602 | 93,307,174 |
| May | 90,498,285 | 95,447,292 |
| June | 113,750,268 | 115,398,815 |
| Total Fuel and Purchased Power Cos | $ 1,645,952,067 | $ 1,617,959,276 |

**Dominion Energy North Carolina**
**North Carolina Recovery Experience**
**Twelve Months Ended June 2020**

| | July-19 | August-19 | September-19 | October-19 | November-19 | December-19 | January-20 | February-20 | March-20 | April-20 | May-20 | June-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **PART I** | | | | | | | | | | | | | |
| FERC Account 501 - Steam Fuel Cost | $ 43,881,172 | $ 33,412,034 | $ 17,014,575 | $ 16,765,761 | $ 28,352,084 | $ 14,626,688 | $ 28,260,209 | $ 15,001,174 | $ 17,447,166 | $ 12,817,381 | $ 15,118,417 | $ 32,318,954 | $ 275,015,616 |
| FERC Account 518 - Nuclear Fuel Cost | $ 15,231,763 | $ 15,540,308 | $ 11,836,710 | $ 13,195,705 | $ 11,296,740 | $ 15,487,082 | $ 15,018,684 | $ 14,947,873 | $ 15,361,034 | $ 13,172,569 | $ 11,600,379 | $ 13,940,167 | $ 166,629,015 |
| FERC Account 547 - Other Fuel Cost | $ 86,424,812 | $ 78,153,990 | $ 68,865,844 | $ 35,248,705 | $ 50,692,530 | $ 100,938,742 | $ 108,644,107 | $ 99,014,725 | $ 65,998,788 | $ 49,105,343 | $ 51,414,855 | $ 58,217,458 | $ 852,719,899 |
| FERC Account 555 - Purchased Power Cost | $ 28,170,168 | $ 25,206,508 | $ 37,403,969 | $ 51,287,167 | $ 59,801,163 | $ 30,129,357 | $ 15,633,578 | $ 14,518,188 | $ 14,996,890 | $ 18,211,881 | $ 17,313,640 | $ 10,922,237 | $ 323,594,746 |
| Total NC System Fuel and Purchased Power Cost | $ 173,707,916 | $ 152,312,841 | $ 135,121,097 | $ 116,497,339 | $ 150,142,518 | $ 161,181,869 | $ 167,556,578 | $ 143,481,960 | $ 113,803,878 | $ 93,307,174 | $ 95,447,292 | $ 115,398,815 | $ 1,617,959,276 |
| Exclude System AFUDC | (20,259) | (21,067) | (14,595) | (19,596) | (17,670) | (21,811) | (21,123) | (21,022) | (21,570) | (18,456) | (18,384) | (20,370) | (235,924) |
| Total NC System Fuel and Purchased Power Cost w/o AFUDC | $ 173,687,656 | $ 152,291,774 | $ 135,106,503 | $ 116,477,743 | $ 150,124,848 | $ 161,160,057 | $ 167,535,455 | $ 143,460,938 | $ 113,782,308 | $ 93,288,719 | $ 95,428,907 | $ 115,378,446 | $ 1,617,723,352 |
| **PART II** | | | | | | | | | | | | | |
| NC Jurisdictional Fuel and Purchased Power Cost w/o AFUDC | $ 8,286,699 | $ 6,459,196 | $ 7,164,508 | $ 5,367,726 | $ 6,403,727 | $ 9,743,328 | $ 7,396,409 | $ 8,149,644 | $ 4,986,762 | $ 3,835,530 | $ 6,680,128 | $ 4,514,793 | $ 78,988,448 |
| Credit for the fuel cost from Non-Requirement Sales | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Credit for the fuel cost from PJM Off-system Sales | $ (20,141) | $ (20,053) | $ (31,941) | $ 2,181 | $ - | $ (46,898) | $ (214,750) | $ (118,806) | $ (590,601) | $ (363,474) | $ (307,994) | $ (207,748) | (1,920,226) |
| Other Fuel Related Adjustments [(1)] | 16,092 | 16,734 | 11,593 | 15,565 | 14,035 | 17,325 | 16,778 | 16,698 | 17,133 | 14,659 | 14,393 | (61,446) | 109,559 |
| Adjusted NC Jurisdiction Fuel and Purchased Power Cost | $ 8,282,649 | $ 6,455,876 | $ 7,144,159 | $ 5,385,472 | $ 6,417,762 | $ 9,713,755 | $ 7,198,437 | $ 8,047,536 | $ 4,413,294 | $ 3,486,715 | $ 6,386,527 | $ 4,245,599 | $ 77,177,781 |
| **PART III** | | | | | | | | | | | | | |
| Adjusted NC Jurisdiction Fuel and Purchased Power Cost | $ 8,282,649 | $ 6,455,876 | $ 7,144,159 | $ 5,385,472 | $ 6,417,762 | $ 9,713,755 | $ 7,198,437 | $ 8,047,536 | $ 4,413,294 | $ 3,486,715 | $ 6,386,527 | $ 4,245,599 | $ 77,177,781 |
| NC Jurisdictional Revenue | (8,998,512) | (7,461,944) | (8,386,983) | (6,408,171) | (4,669,745) | (7,706,220) | (5,775,406) | (6,609,780) | (4,837,264) | (5,709,665) | (8,751,498) | (5,911,722) | (81,226,910) |
| (Over)/Under Recovery | $ (715,863) | $ (1,006,068) | $ (1,242,824) | $ (1,022,699) | $ 1,748,017 | $ 2,007,535 | $ 1,423,032 | $ 1,437,755 | $ (423,970) | $ (2,222,950) | $ (2,364,971) | $ (1,666,123) | $ (4,049,129) |
| Cumulative (Over)/Under Recovery | $ (715,863) | $ (1,721,930) | $ (2,964,754) | $ (3,987,453) | $ (2,239,437) | $ (231,902) | $ 1,191,130 | $ 2,628,885 | $ 2,204,915 | $ (18,035) | $ (2,383,006) | $ (4,049,129) | |

[(1)] Includes jurisdictional AFUDC, AFUDC tax credits and late entries.

# Dominion Energy North Carolina
# Actual Kilowatt-hour (kWh) Sales
# Twelve Months Ended June 2020

***(In Thousands)***

| | System kWh Sales* (1) | North Carolina Retail kWh Sales* (2) |
|---|---|---|
| July 2019 | 8,784,782 | 419,007 |
| August | 8,182,298 | 346,935 |
| September | 7,392,635 | 391,869 |
| October | 6,498,188 | 299,324 |
| November | 6,819,294 | 290,757 |
| December | 7,554,644 | 456,560 |
| January 2020 | 7,589,479 | 335,063 |
| February | 6,788,147 | 385,617 |
| March | 6,418,501 | 281,305 |
| April | 5,549,679 | 228,173 |
| May | 6,052,091 | 423,653 |
| June | 7,144,438 | 279,564 |
| Total kWh Sales | 84,774,176 | 4,137,826 |

*Including unbilled kWh sales.

# Dominion Energy North Carolina
# Actual Fuel Related Revenues
# Twelve Months Ended June 2020

| | System Fuel Related Revenues As Booked* | North Carolina Retail Fuel Factor Related Revenues* | |
|---|---|---|---|
| | | Current Period | EMF Rider B |
| | (1) | (2) | (3) |
| July 2019 | $204,307,969 | $ 8,998,512 | 1,629,361 |
| August | 189,538,803 | 7,461,944 | 1,351,089 |
| September | 170,745,997 | 8,386,983 | 1,518,898 |
| October | 149,582,621 | 6,408,171 | 1,160,479 |
| November | 155,452,436 | 4,669,745 | 1,156,450 |
| December | 172,412,262 | 7,706,220 | 1,736,077 |
| January 2020 | 176,175,186 | 5,775,406 | 1,302,290 |
| February | 157,378,357 | 6,609,780 | 1,490,824 |
| March | 148,894,412 | 4,837,264 | 1,090,823 |
| April | 128,157,284 | 5,709,665 | (841,681) |
| May | 115,991,574 | 8,751,498 | 56,645 |
| June | 112,565,808 | 5,911,722 | 39,102 |
| Total Fuel Related Revenues | $ 1,881,202,710 | $ 81,226,910 | $ 11,690,358 |

*Including unbilled kWh revenues.

# Dominion Energy North Carolina
## Inventories of Fuel Burned
## As of June 30, 2020

| Fuel | Inventory Measure | | Inventory Volume | Inventory Value |
|---|---|---|---|---|
| (1) | (2) | | (3) | (4) |
| Coal [b] | Tons | Coal Rec | 1,619,028 | $ 106,542,539 |
| Wood [b] | Tons | Wood & Jet Fuel Rec | 60,308 | 1,600,712 |
| Light Oil [a] | Gallons | Oil Rec | 62,785,307 | 128,701,014 |
| Heavy Oil [a] | Barrels | Oil Rec | 1,417,971 | 67,617,669 |
| Jet Fuel [a] | Gallons | Wood & Jet Fuel Rec | 37,609 | 104,620 |
| Natural Gas [a] | Dth | Power Gen. Summary | 2,038,335 | 3,167,990 |
| Nuclear Fuel Stock [b] | N/A | | | 487,357,996 |
| Total | | | | $ 795,092,540 |

(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 590**

**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 Manager-Gas Supply 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 group 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, 2019 to June 30, 2020 ("Test Period"), in compliance with Rule 8-55(e)(5).

**Q. Are you sponsoring any exhibits?**

A. Yes. Company Exhibit DEH-1, consisting of one schedule, was prepared under my direction and is accurate and complete to the best of my knowledge. Exhibit 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. The nuclear fuel market has softened considerably in the past eight to nine years with uranium, conversion, and enrichment markets all showing varying levels of decreased prices. This is largely due to the long-lasting impact of the devastating Japanese earthquake and tsunami of March 2011, which has been discussed in prior North Carolina fuel cases. But there have been other factors influencing this trend as well such as clear reductions in demand (*e.g.*, Germany's decision to permanently shut down eight reactors and the closing and announced closings of several U.S. reactors). There have also been some reductions in supply including idling of uranium production (most notably

**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.

**Q. Does the Company currently have a price hedging program?**

A. Yes, the Company has a price hedging program under which the Company price hedges commodities needed for power generation using a range of volume targets, which gradually decrease over a three-year period. The Company's fuel price hedging program is discussed in greater detail in the Fuel Procurement Strategy Report filed with the Virginia Commission on January 31, 2020, in Case No. PUR-2019-00070 (the "Report"). In summary, as that Report describes, 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 duration of these physical procurement agreements is staggered (*i.e.*, different contract lengths) and can also include a fixed price component, the inclusion of which creates a price hedge. Managing price volatility is an important aspect of the Company's price hedging program and can be further supported, as needed, using financial transactions.

## SECTION II
## NATURAL GAS PROCUREMENT

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

A. The Company employs 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 the interstate pipeline capacity release and physical supply markets to augment its transportation portfolio and enhance reliability at a reasonable cost.

**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 61% and, on average, over 53% of the Company's electricity generation, during the Test Period. Brunswick, Greensville and Warren County Power Stations are the Company's newest, most efficient natural gas-fired combined cycle stations, with a combined maximum generation capacity of approximately 4,500 MW. These power stations rely solely on the reliable and consistent delivery of competitively priced natural gas at each location via firm pipeline capacity. The Company's firm transportation capacity on the Transco interstate pipeline ("Transco") is especially important when fueling these three stations. Warren County's winter natural gas deliveries rely on upstream deliveries from Transco. Namely, during winter periods, the Company must utilize its Transco firm capacity to deliver natural gas into Columbia Gas Transmission's system at the Rockville, Maryland interconnect (Zone 6) with Transco. Finally, both Brunswick and Greensville rely 100% on Transco natural gas deliveries, year-round.

**Q. Mr. Hinson, have there been significant changes in pipeline constraints?**

A. Yes, the Company has experienced greater interstate pipeline constraints negatively affecting the flexibility of its natural gas-fired generation fleet. Notably, within the past two years, Transco implemented certain Priority of Service (POS) changes to its firm transportation service tariff restricting segmentation flexibility affecting the Company's ability to offer and fuel certain gas-fired generation stations. Effective April 2019, Transco also began to enforce (a change in its longstanding business practice) an existing daily imbalance limit. Together, these changes have limited the Company's ability to handle natural gas consumption swings typically caused by various factors including, but not limited to: PJM directives, unforeseen outages, system emergencies and electric generation variability. Furthermore, Transco's daily imbalance restriction was in addition to Transco issuing operational flow orders ("OFOs") during times of constraint. Transco OFO constraints were in effect approximately 86% of the time during the Test Period, however, together with the restrictions mentioned above, Transco is effectively 100% constrained.

Q. **Mr. Hinson, you discuss how pipeline constraints negatively affect the flexibility of the Company's natural gas-fired generation fleet. How else can pipeline constraints be viewed?**

A. Limiting the Company's ability to handle natural gas consumption swings to accommodate the variability of electric power generation requirements ultimately limits the Company's electric dispatch efficiencies and related costs and exposes the Company to PJM capacity performance risk.

Q. **In addition to the limited flexibility described above, has the Company experienced other pipeline issues adversely affecting its ability to meet electric generation service obligations for its customers?**

A. Yes. The Company has experienced forced unit outages on its newest, combined cycle stations due to natural gas pressure issues on the Transco interstate pipeline.

**Q. How has the Company addressed these operational limitations and issues on interstate pipelines?**

A. In 2014, the Company contracted for firm transportation capacity, with an initial, estimated in-service date of fourth quarter 2018, on the Atlantic Coast Pipeline ("ACP"). ACP was designed to provide a firm transportation path from the competitively priced and abundant, Marcellus natural gas production region to various points in Virginia and North Carolina. Specifically, the Company's long-term firm contract had primary firm delivery points at its Brunswick and Greensville power stations. However, on July 5, 2020 ACP announced it had cancelled the project "due to ongoing delays and increasing cost uncertainty which threaten the economic viability of the project."

Q. **What actions has the Company undertaken, in anticipation of ACP's in-service date, to mitigate or otherwise address these operational limitations on interstate pipelines that negatively affect its ability to meet electric generation service obligations?**

A. To date, the Company has prudently managed pipeline outages and constraints using short-term market solutions and alternative generation options available at the time. These mitigation efforts include: pipeline segmentation, third-party natural gas supply purchases, winter peaking supply purchases, use of alternate fuel, and short-term interstate pipeline capacity purchases.

**Q. Has the Company employed other solutions, not listed in your short-term market list, above?**

A. Yes. For the Company's most recent, 3x1, combined cycle power station builds (Warren Co., Brunswick Co., and Greensville Co.), their anticipated, daily, natural gas consumption warranted the Company entering into incremental, firm pipeline capacity contracts with firm delivery points at the respective station locations. These firm pipeline contracts were placed in service before the respective power station(s) become operational, to allow for station testing. As an example, the Company's firm capacity on Transco (serving Brunswick Co station) was in service early enough to cover two winter periods, prior to the

Brunswick Co. station becoming operational.

**Q. What is the significance of these firm pipeline capacity contracts?**

A. While they were available in time to support power station testing, at least for finite time periods, these contracts had available capacity to help address various pipeline constraints that would otherwise negatively affect the Company's ability to meet its electric generation obligations. However, since these power stations have become operational, this available capacity is now dedicated to serving these stations, and others (as allowed by pipeline constraints), as part of the Company's firm pipeline capacity portfolio. Furthermore, with no new, large scale, gas-fired power stations planned on the near horizon, the Company does not and will not have this type of solution available to help address current interstate pipeline constraints.

**Q. Does this place additional reliance on the short-term market solutions you mentioned earlier in your testimony?**

A. Yes. The Company is now solely reliant on short-term market solutions. However, it is important to understand that each of these short-term solutions have distinct limitations, such as pipeline and supplier market availability, on-site alternate fuel availability and price. None of these market solutions or alternate fuel options should be considered as long-term and reliable methods to meet the Company's firm, electric generation obligations to its customers and PJM.

**Q. Mr. Hinson, given the rise in interstate pipeline constraints and other operational pipeline issues and the cancellation of the ACP, what does this mean for the Company's current level of contracted firm interstate pipeline capacity?**

A. In plain terms and specifically on Transco, the Company's firm pipeline transportation contracts do not provide the same level of flexibility experienced only a few years ago. Gone are the days when pipelines had large volumes of unsubscribed capacity which accommodated the relatively small consumption requirements of natural gas generators, as evidenced by the constraints and pressure issues discussed above. The result is that the Company does not have sufficient, firm interstate pipeline capacity to meet its electric generation obligations, especially during the winter months. As I mentioned earlier in my testimony, the mitigation measures employed to date, by the Company, to address ongoing interstate pipeline constraints cannot be considered long-term, reliable solutions. As the proportion of the Company's natural gas-fired generation has risen, so too has the complexity to meet the natural gas fueling requirements of these assets.

**Q. Does the Company have a long-term solution to address current interstate pipeline constraints and operational issues?**

A. The Company is currently evaluating long-term solutions to continue to meet its firm electric generation requirements given current and likely future interstate pipeline constraints. The result will account for a multitude of variables both on the electric generation demand and supply requirement sides of the equation.

Stated differently, the Company must account for recent changes, as well as those projected due to factors such as the role of quickly dispatchable natural gas generation to supplement increased intermittent renewable energy and, changes in state and federal regulations, and increased risk associated with pipeline infrastructure development. Ultimately, the Company's solutions will be focused on providing safe, reliable and cost-effective means by which it can continue to fuel its natural gas-fired generation fleet.

## 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.

## 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. 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 primary 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
## <u>OIL PROCUREMENT</u>

**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, it does.

**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. In 2013, Mr. Hinson assumed his current role as Manager – Gas Supply.

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 Utility Commission and the State Corporation Commission of Virginia.

**DOMINION ENERGY NORTH CAROLINA**
**SUMMARY REPORT OF FUEL TRANSACTIONS WITH AFFILIATES**
**FOR THE PERIOD JULY 2019 - JUNE 2020**
**(IN THOUSANDS)**

## Dominion Energy North Carolina Receiving from Affiliate:

**Docket No. E-22, Sub 590**

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

| Month | Amount |
|---|---|
| July-19 | $88,443 |
| August-19 | $84,797 |
| September-19 | $69,440 |
| October-19 | $35,741 |
| November-19 | $51,104 |
| December-19 | $101,420 |
| January-20 | $110,212 |
| February-20 | $99,602 |
| March-20 | $65,961 |
| April-20 | $49,457 |
| May-20 | $51,528 |
| June-20 | $58,900 |
| Total Charged to FERC Account 151 | $866,605 |

**DOMINION ENERGY NORTH CAROLINA**
**SUMMARY REPORT OF FUEL TRANSACTIONS WITH AFFILIATES**
**FOR THE PERIOD JULY 2019 - JUNE 2020**

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

**Docket No. E-22, Sub 590**

| | Volume | | | Dollars | | | WACOG | | |
|---|---|---|---|---|---|---|---|---|---|
| | Purchase | Sale | Difference | Purchase | Sale | Difference | Purchase | Sale | Difference |
| Jul-19 | 30,403,261 | 30,404,980 | (1,719) | $ 64,988,255.26 | $ 64,990,774.85 | $ (2,519.59) | $ 2.138 | $ 2.138 | 0.000 |
| Aug-19 | 29,433,110 | 29,433,974 | (864) | $ 57,178,959.94 | $ 57,192,683.82 | $ (13,723.87) | $ 1.943 | $ 1.943 | (0.000) |
| Sep-19 | 28,345,243 | 28,345,473 | (230) | $ 54,033,414.12 | $ 54,034,239.81 | $ (825.69) | $ 1.906 | $ 1.906 | (0.000) |
| Oct-19 | 19,118,959 | 19,119,157 | (198) | $ 31,421,366.47 | $ 31,421,980.92 | $ (614.45) | $ 1.643 | $ 1.643 | (0.000) |
| Nov-19 | 23,923,722 | 23,924,549 | (827) | $ 61,400,048.55 | $ 61,402,043.70 | $ (1,995.15) | $ 2.566 | $ 2.566 | 0.000 |
| Dec-19 | 24,793,840 | 24,794,653 | (813) | $ 82,860,109.12 | $ 82,864,314.11 | $ (4,204.99) | $ 3.342 | $ 3.342 | (0.000) |
| Jan-20 | 26,878,911 | 26,879,409 | (498) | $ 87,907,027.90 | $ 87,909,762.39 | $ (2,734.48) | $ 3.270 | $ 3.271 | (0.000) |
| Feb-20 | 24,601,251 | 24,603,198 | (1,947) | $ 82,673,922.14 | $ 82,678,220.91 | $ (4,298.77) | $ 3.361 | $ 3.360 | 0.000 |
| Mar-20 | 27,404,464 | 27,404,464 | - | $ 48,256,423.72 | $ 48,256,085.22 | $ 338.50 | $ 1.761 | $ 1.761 | 0.000 |
| Apr-20 | 25,840,137 | 25,840,300 | (163) | $ 38,335,381.55 | $ 38,335,345.75 | $ 35.80 | $ 1.484 | $ 1.484 | 0.000 |
| May-20 | 23,924,706 | 23,924,706 | - | $ 34,370,155.30 | $ 34,370,199.84 | $ (44.54) | $ 1.437 | $ 1.437 | (0.000) |
| Jun-20 | 26,917,845 | 26,918,400 | (555) | $ 41,590,496.70 | $ 41,591,421.00 | $ (924.30) | $ 1.545 | $ 1.545 | (0.000) |
| Total | 311,585,449 | 311,593,263 | (7,814) | $ 685,015,560.76 | $ 685,047,072.28 | $ (31,511.52) | | | |

**DOMINION ENERGY NORTH CAROLINA**
**SUMMARY REPORT OF FUEL TRANSACTIONS WITH AFFILIATES**
**FOR THE PERIOD JULY 2019 - JUNE 2020**

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

**Docket No. E-22, Sub 590**

July 2019 - June 2020 Contracted Affiliated Fuel Transactions

**There were no affiliate transactions of Fuel from July 2019 through June 2020.**

**DIRECT TESTIMONY OF**
**TOM A. BROOKMIRE**
**ON BEHALF OF**
**DOMINION ENERGY NORTH CAROLINA**
**BEFORE THE**
**NORTH CAROLINA UTILITIES COMMISSION**
**DOCKET NO. E-22, SUB 590**

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

A. My name is Tom A. Brookmire, and I am the Manager of Nuclear Fuel Procurement. My business address is Innsbrook Technical Center, 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am responsible for nuclear fuel procurement, fuel-related project management, long-term nuclear spent fuel disposal, and nuclear fuel 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, 2019 through June 30, 2020 ("test period"), in compliance with Rule 8-55(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
## <u>NUCLEAR FUEL MARKET AND COMPONENTS</u>

**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. The nuclear fuel market has softened considerably in the past eight to nine years with uranium, conversion, and enrichment markets all showing varying levels of decreased prices. This is largely due to the long-lasting impact of the devastating Japanese earthquake and tsunami of March 2011, which has been discussed in prior North Carolina fuel cases. But there have been other factors influencing this trend as well such as clear reductions in demand (*e.g.*, Germany's decision to permanently shut down eight reactors and the closing and announced closings of several U.S. reactors). There have also been some reductions in supply including idling of uranium production (most notably idling of uranium production at Cameco's McArthur River and Cigar Lake mines and some Kazakhstan production), postponement and deferral of new uranium mines and mine capacity expansions, the idling of a U.S.-based uranium conversion plant along with delays in planned increases in uranium enrichment capacity which have offset most of the reductions in demand. Uranium market prices have continued to be depressed, but prices have increased somewhat in more recent months.

The price for conversion services has recently experienced some upward price lift in the last couple of years due to production cuts in the US. Term and particularly spot conversion prices have remained high due to reductions in near term supply and concern over the lack of investment in new conversion production facilities, and the possibility for shortfalls in long-term capacity.

The cost for enrichment services stabilized somewhat during the last year, although prices in this market are still depressed. Nevertheless, there has been some uplift in term price due to some recent interest in long-term enrichment services.

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 general consensus is that costs will continue to increase due to regulatory requirements, reduced competition, and reactor demand both in the U.S. and abroad. Additionally, the parent companies for both U.S. nuclear fuel fabricators (Westinghouse Electric Corporation ("Westinghouse") and Framatome) have experienced financial distress, which is likely to put upward pressure on fabrication costs and nuclear fuel engineering services.

Calendar year 2019 saw no restarts in Japan. Five reactors have met new standards and were restarted in 2018. The timing and extent of other reactor restarts in Japan currently remains uncertain. China continues to have an aggressive nuclear energy program and continues to be a significant factor in supply and demand for uranium. It uses its own indigenous sources for uranium conversion and enrichment and is not a significant player in the global economy for these services. China currently has 45 reactors in operation, 12 plants under construction, and others in planning.

**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 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. Finally, the Company has been active in the market and has executed some market-based and fixed price contracts, allowing the Company to take advantage of current lower prices for the benefit of customers.

**Q. Two U.S. miners filed a Section 232 petition in January 2018. How will this potentially affect the Company's fuel supply?**

A. In July 2019, contrary to the Department of Commerce's recommendation, President Trump decided to take no action with respect to any remedies associated with the uranium miners' Section 232 petition. In lieu thereof, President Trump formed the United Stated Nuclear Fuel Working Group consisting of certain cabinet members and other high-level agency staff. The Working Group was requested to examine the current state of domestic nuclear fuel production to reinvigorate the entire nuclear fuel supply chain, consistent with United States national security and nonproliferation goals. The Working Group's report was issued on April 23, 2020, but to date no significant market impacts have been realized.

**Q. Could sanctions resulting from the Iran Nuclear Deal affect nuclear fuel costs in the United States?**

A. Yes, it could. However, it's not clear at this point if any sanctions would be imposed, and, if they are, what downstream effects they might have on the markets.

## 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 I explained in my 2019 direct 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

## TOM A. BROOKMIRE

Tom A. Brookmire is a graduate of Virginia Tech with a Bachelor of Science degree in Nuclear Science (1983), and a Master's degree in Engineering in Nuclear Engineering from the University of Virginia (1988). He is a registered professional engineer in the Commonwealth of Virginia.

Mr. Brookmire joined with Virginia Electric and Power Company in 1983, and has worked since then in staff and management positions involving nuclear fuel. His current responsibilities include procurement of nuclear fuel and related services, nuclear fuel-related project management, long-term disposal of spent nuclear fuel, and the projection of nuclear prices and related capital costs and expense rates.

**DIRECT TESTIMONY OF**
**GEORGE G. BEASLEY**
**ON BEHALF OF**
**DOMINION ENERGY NORTH CAROLINA**
**BEFORE THE**
**NORTH CAROLINA UTILITIES COMMISSION**
**DOCKET NO. E-22, SUB 590**

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

A. My name is George G. Beasley. My business address is 120 Tredegar Street, Richmond, Virginia 23219. My title is Regulatory Specialist 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. Beasley, 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 twelve months ended June 30, 2020 (the "test period"), to become effective on February 1, 2021. I am also sponsoring the calculation of the adjustment to total system sales (kWh) for the twelve months ended June 30, 2020, due to change in usage, weather normalization, and customer growth.

**Q. In the course of your testimony will you introduce an exhibit?**

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

**Q. Mr. Beasley, please explain Schedule 1.**

A. Schedule 1 of Exhibit GGB-1 provides a summary of jurisdictional and total system kWh sales for the twelve months ended June 30, 2020, 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 (2,257,644) kWh. The adjustment to total system kWh at sales level is 699,552,428 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 579) with one exception. The workpapers supporting the change in usage, weather normalization, and customer growth calculation are provided in response to Rule R8-55 (e) (2). The Federal Government customers and usage in the Virginia Jurisdiction were removed and placed in the Virginia Non-Jurisdiction class and combined with the MS class. This was based upon an order from the Virginia State Corporation Commission to remove Federal Government customers and usage from the Virginia Jurisdiction cost of service. This revised MS/Federal Government group of customers in Virginia, although small in number and outside the North Carolina Jurisdiction, increased significantly in proportion due to this reclassification. This increase in customers and their associated usage created model results that predicted an increase in customers and kWh adjustments that are unlikely for the MS/Federal Government class in Virginia. Therefore, in this proceeding we propose no adjustment for increased usage, weather effect, or customer growth in the MS/Federal Government class.

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

A. Yes. Schedule 2 of Exhibit GGB-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 $1,568,811,597(as provided in Schedule 4 of Exhibit JDM-1) is divided by system sales of 85,444,348,726 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 $0.01838/ 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 579). The Base Fuel Component for each class determined in Docket No. E-22, Sub 579 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. Please describe the Experience Modification Factor, Rider B, applicable to the North Carolina jurisdiction.**

A. Schedule 3 of Exhibit GGB-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 over recovered fuel expense, for the period July 1, 2019 through June 30, 2020, of ($4,049,129) (as provided in Schedule 2 of Exhibit RTC-1) was adjusted by ($641,112) to account for interest. The total net balance of ($4,690,241) was then divided by North Carolina test year sales of 4,015,131,356 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 ($0.00117)/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. 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, 2021.**

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

| Customer Class | Total |
|---|---|
| Residential | $0.01737 |
| SGS & PA | $0.01735 |
| LGS | $0.01722 |
| Schedule NS | $0.01694 |
| 6VP | $0.01671 |
| Outdoor Lighting | $0.01737 |
| Traffic | $0.01737 |

A comparison of the present and proposed total rates for each class is shown on my Schedule 4, Pages 1 and 2 of Exhibit GGB-1.

**Q. Do you have a schedule that shows the total fuel revenue recovery by class and for the North Carolina jurisdiction for the 2021 fuel year?**

A. Yes. Schedule 5 of Exhibit GGB-1 shows the total fuel revenue recovery by class and for the North Carolina jurisdiction for the 2021 fuel year. For the North Carolina jurisdiction, the proposed jurisdictional fuel cost levels result in a total fuel recovery decrease of $15,418,104.

**Q. Have you included in your exhibit a revision to the Fuel Cost Rider A and EMF Rider B which will reflect the Company's proposed total fuel factors, to be effective February 1, 2021?**

A. Yes. Schedule 6, Pages 1 and 2 of Exhibit GGB-1 provides the revised Fuel Charge Rider A and EMF Rider B that the Company proposes to become effective on and after February 1, 2021.

**Q. Mr. Beasley, would you explain how these proposed changes in the fuel factor will affect customers' bills? Use bill amounts as of August 1, 2020 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 (4 summer months and 8 base months) would decrease by $3.95 from $111.46 to $107.51, or by 3.54%. 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 (4 summer months and 8 base months) would decrease by $49.25 from $1,085.35 to $1,036.10, or by 4.54%. For Rate Schedule 6P (large general service), for a 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 $2,246.40 from $38,107.41 to $35,861.01, or by 5.89%.

**Q. Does this conclude your testimony?**

A. Yes, it does.

## BACKGROUND AND QUALIFICATIONS
## OF
## GEORGE G. BEASLEY

George G. Beasley received a Bachelor of Science degree in Finance from Virginia Commonwealth University in 1996. Mr. Beasley started his career with the Company in 2008 as a Sr. Business Performance Analyst. In 2011, Mr. Beasley was promoted to Supervisor Customer Revenue Management Planning and Analysis where he was responsible for the analytical support of our electric Credit and Billing functions. In 2015, Mr. Beasley took over the Customer Billing Compliance and Quality Control Manager position and was responsible for the auditing and quality control of changes implemented into the Billing system including rate and regulatory changes. In 2017, Mr. Beasley joined the Rate Department as a Regulatory Specialist to work in the Rate Design section, where he assists with regulatory filings, the design of rates, and performing analysis related to the Company's Virginia and North Carolina service territories. Mr. Beasley has previously filed testimony with the North Carolina Utilities Commission and the State Corporation Commission of Virginia.

**SUMMARY OF KWH ATTRIBUTABLE TO
CHANGE IN USAGE, WEATHER NORMALIZATION, AND CUSTOMER GROWTH
TWELVE MONTHS ENDED JUNE 30, 2020**

**SYSTEM**

| LINE | JURISDICTION | CHANGE IN USAGE KWH | WEATHER NORM. KWH | CUSTOMER GROWTH KWH | TOTAL KWH |
|---|---|---|---|---|---|
| 1) | NORTH CAROLINA (A) | (49,039,707) | 40,500,503 | 6,281,560 | (2,257,644) |
| 2) | VIRGINIA | 429,268,737 | 240,949,378 | 186,201,503 | 856,419,618 |
| 3) | COUNTY | (74,750,369) | (43,036,429) | (21,694,715) | (139,481,513) |
| 4) | STATE | (36,941,992) | (13,377,862) | 11,274,379 | (39,045,475) |
| 5) | MS / FEDERAL GOVERNMENT | 0 | 0 | 0 | 0 |
| 7) | FERC | 0 | (5,462,260) | 0 | (5,462,260) |
| 8) | SYSTEM KWH AT SALES LEVEL | 268,536,669 | 219,573,330 | 182,062,727 | 670,172,726 |
| 9) | SUBTOTAL - SYSTEM KWH AT GENERATION LEVEL (LINE 8 x 2019 EXPANSION FACTOR) (B) | | | | 699,552,428 |

NOTES

( ) DENOTES NEGATIVE VALUE

| (A) NORTH CAROLINA BY CLASS | CHANGE IN USAGE KWH | WEATHER NORM. KWH | CUSTOMER GROWTH KWH | TOTAL KWH |
|---|---|---|---|---|
| RESIDENTIAL | (5,070,970) | 37,500,695 | 8,928,927 | 41,358,652 |
| SGS / PA | (15,899,623) | 2,999,808 | 1,204,303 | (11,695,512) |
| LGS | 6,938,636 | 0 | (4,044,800) | 2,893,836 |
| NS | (26,408,022) | 0 | 0 | (26,408,022) |
| 6VP | (8,472,578) | 0 | 0 | (8,472,578) |
| ODL & ST LTS | (109,375) | 0 | 194,327 | 84,952 |
| TRAFFIC | (17,775) | 0 | (1,197) | (18,972) |
| TOTAL | (49,039,707) | 40,500,503 | 6,281,560 | (2,257,644) |

(B) 2019 SYSTEM EXPANSION FACTOR IS 1.043839

**DOMINION ENERGY NORTH CAROLINA**
**CALCULATION OF SYSTEM AVERAGE FUEL FACTOR**
**TWELVE MONTHS ENDED JUNE 30, 2020**
**TO BE EFFECTIVE FEBRUARY 1, 2021**

| | | |
|---|---|---|
| EXPENSE: | 12 MONTH NORMALIZED SYSTEM FUEL EXPENSE (A) | $1,568,811,597 |
| SALES: | 12 MONTHS SYSTEM KWH SALES ADJUSTED<br>FOR CHANGE IN USAGE, WEATHER AND CUSTOMER GROWTH (B) | 85,444,348,726 |
| FEE: | NORTH CAROLINA REGULATORY FEE ADJUSTMENT FACTOR | 1.0013 |

FACTOR = $\frac{\$1,568,811,597}{85,444,348,726} \times 1.0013$

FACTOR = $0.01838 / KWH (C) (D)

NOTES

(A) FROM COMPANY EXHIBIT NO. JDM-1 SCHEDULE 4

| | | |
|---|---|---|
| (B) | SYSTEM KWH AT SALES LEVEL [COMPANY EXHIBIT RC-1, SCHEDULE 3] | 84,774,176,000 |
| | PLUS: SYSTEM KWH USAGE, WEATHER, GROWTH ADJUSTMENT<br>[COMPANY EXHIBIT NO. GGB-1, SCHEDULE 1, LINE 8] | 670,172,726 |
| | TOTAL SYSTEM SALES | 85,444,348,726 |

(C) THE NORTH CAROLINA JURISDICTIONAL PROPOSED BASE FUEL FACTOR IS $0.02116/KWH

(D) WITHOUT NC REGULATORY FEE $0.01836 /KWH

**DOMINION ENERGY NORTH CAROLINA**
**CALCULATION OF FUEL COST RIDER A**
**TWELVE MONTHS ENDED JUNE 30, 2020**
**TO BE EFFECTIVE FEBRUARY 1, 2021**

| | (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 | 1,597,301,652 | $0.01838 | $29,358,404 | 1.05111700 | 1,678,950,921 | | $0.01765 | $0.01855 | $0.02118 | ($0.00263) |
| SGS & PA | 655,330,488 | $0.01838 | $12,044,974 | 1.04999590 | 688,094,326 | | $0.01765 | $0.01853 | $0.02115 | ($0.00262) |
| LGS | 651,610,836 | $0.01838 | $11,976,607 | 1.04171877 | 678,795,240 | | $0.01765 | $0.01839 | $0.02098 | ($0.00259) |
| SCHEDULE NS | 838,113,978 | $0.01838 | $15,404,535 | 1.02505300 | 859,111,247 | | $0.01765 | $0.01809 | $0.02036 | ($0.00227) |
| 6VP | 246,776,422 | $0.01838 | $4,535,751 | 1.01053200 | 249,375,471 | | $0.01765 | $0.01784 | $0.02065 | ($0.00281) |
| OUTDOOR LIGHTING | 25,583,952 | $0.01838 | $470,233 | 1.05111700 | 26,891,727 | | $0.01765 | $0.01855 | $0.02118 | ($0.00263) |
| TRAFFIC | 414,028 | $0.01838 | $7,610 | 1.05111700 | 435,192 | | $0.01765 | $0.01855 | $0.02118 | ($0.00263) |
| TOTAL | 4,015,131,356 | | $73,798,114 | (3a) | 4,181,654,123 | (5a) | | | | |

NOTES

(A)

| | TEST YR KWH | CHG IN USAGE, WEATHER CUST GROWTH ADJ | TOTAL* |
|---|---|---|---|
| RESIDENTIAL | 1,555,943,000 | 41,358,652 | 1,597,301,652 |
| SGS & PA | 667,026,000 | (11,695,512) | 655,330,488 |
| LGS | 648,717,000 | 2,893,836 | 651,610,836 |
| SCHEDULE NS | 864,522,000 | (26,408,022) | 838,113,978 |
| 6VP | 255,249,000 | (8,472,578) | 246,776,422 |
| OUTDOOR LIGHTING | 25,499,000 | 84,952 | 25,583,952 |
| TRAFFIC | 433,000 | (18,972) | 414,028 |
| TOTAL | 4,017,389,000 | (2,257,644) | 4,015,131,356 |

* CLASS KWH AT SALES LEVEL PLUS CHANGE IN USAGE, WEATHER NORMALIZATION
AND CUSTOMER GROWTH [COMPANY EXHIBIT NO. GGB-1 SCHEDULE 1]

(B) IN $/KWH

**DOMINION ENERGY NORTH CAROLINA**
**CALCULATION OF EXPERIENCE MODIFICATION FACTOR - RIDER B**
**TWELVE MONTHS ENDED JUNE 30, 2020**
**TO BE EFFECTIVE FEBRUARY 1, 2021**

| | (1) | (2) | (3) | | (4) | (5) | | (6) |
|---|---|---|---|---|---|---|---|---|
| CUSTOMER CLASS | KWH SALES (A) | NC JURISDICTIONAL EMF (B) | FUEL REVENUE UNIFORM EMF (1) x (2) | | CLASS EXPANSION FACTOR | CLASS KWH @ GENERATION LEVEL (1) x (4) | | UNIFORM EMF @ GENERATION LEVEL (3a) / (5a) |
| RESIDENTIAL | 1,597,301,652 | ($0.00117) | ($1,868,843) | | 1.05111700 | 1,678,950,921 | | ($0.00112) |
| SGS & PA | 655,330,488 | ($0.00117) | ($766,737) | | 1.04999590 | 688,094,326 | | ($0.00112) |
| LGS | 651,610,836 | ($0.00117) | ($762,385) | | 1.04171877 | 678,795,240 | | ($0.00112) |
| SCHEDULE NS | 838,113,978 | ($0.00117) | ($980,593) | | 1.02505300 | 859,111,247 | | ($0.00112) |
| 6VP | 246,776,422 | ($0.00117) | ($288,728) | | 1.01053200 | 249,375,471 | | ($0.00112) |
| OUTDOOR LIGHTING | 25,583,952 | ($0.00117) | ($29,933) | | 1.05111700 | 26,891,727 | | ($0.00112) |
| TRAFFIC | 414,028 | ($0.00117) | ($484) | | 1.05111700 | 435,192 | | ($0.00112) |
| TOTAL | 4,015,131,356 | | ($4,697,704) | (3a) | | 4,181,654,123 | (5a) | |

NOTES

(A) FROM COMPANY EXHIBIT NO. GGB-1 SCHEDULE 2, PAGE 2

(B) IN $/KWH

**DOMINION ENERGY NORTH CAROLINA**
**CALCULATION OF EXPERIENCE MODIFICATION FACTOR - RIDER B**
**TWELVE MONTHS ENDED JUNE 30, 2020**
**TO BE EFFECTIVE FEBRUARY 1, 2021**

| | (1) | (2) | (3) | | (4) | (5) | | (6) | (7) |
|---|---|---|---|---|---|---|---|---|---|
| CUSTOMER CLASS | KWH SALES (A) | NC JURISDICTIONAL EMF (B) | FUEL REVENUE UNIFORM EMF (1) x (2) | | CLASS EXPANSION FACTOR | CLASS KWH @ GENERATION LEVEL (1) x (4) | | UNIFORM EMF @ GENERATION LEVEL (3a) / (5a) | VOLTAGE DIFFERENTIATED EMF @ SALES LEVEL (4) x (6) |
| RESIDENTIAL | 1,597,301,652 | ($0.00117) | ($1,868,843) | | 1.05111700 | 1,678,950,921 | | ($0.00112) | ($0.00118) |
| SGS & PA | 655,330,488 | ($0.00117) | ($766,737) | | 1.04999590 | 688,094,326 | | ($0.00112) | ($0.00118) |
| LGS | 651,610,836 | ($0.00117) | ($762,385) | | 1.04171877 | 678,795,240 | | ($0.00112) | ($0.00117) |
| SCHEDULE NS | 838,113,978 | ($0.00117) | ($980,593) | | 1.02505300 | 859,111,247 | | ($0.00112) | ($0.00115) |
| 6VP | 246,776,422 | ($0.00117) | ($288,728) | | 1.01053200 | 249,375,471 | | ($0.00112) | ($0.00113) |
| OUTDOOR LIGHTING | 25,583,952 | ($0.00117) | ($29,933) | | 1.05111700 | 26,891,727 | | ($0.00112) | ($0.00118) |
| TRAFFIC | 414,028 | ($0.00117) | ($484) | | 1.05111700 | 435,192 | | ($0.00112) | ($0.00118) |
| TOTAL | 4,015,131,356 | | ($4,697,704) | (3a) | | 4,181,654,123 | (5a) | | |

**DOMINION ENERGY NORTH CAROLINA**
**TOTAL FUEL COST LEVEL - PRESENT AND PROPOSED**
**TO BE EFFECTIVE FEBRUARY 1, 2021**

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| NC JURISDICTION | BASE FUEL COMPONENT $/KWH | RIDER A FUEL CHARGE $/KWH | RIDER B EMF $/KWH | TOTAL FUEL RATE $/KWH |
| PRESENT | $0.02092 | $0.00000 | $0.00013 | $0.02105 |
| PROPOSED | $0.02092 | ($0.00254) | ($0.00117) | $0.01721 |
| CHANGE | $0.00000 | ($0.00254) | ($0.00130) | ($0.00384) |

| RESIDENTIAL | BASE FUEL COMPONENT $/KWH | RIDER A FUEL CHARGE $/KWH | RIDER B EMF $/KWH | TOTAL FUEL RATE $/KWH |
|---|---|---|---|---|
| PRESENT | $0.02118 | $0.00000 | $0.00014 | $0.02132 |
| PROPOSED | $0.02118 | ($0.00263) | ($0.00118) | $0.01737 |
| CHANGE | $0.00000 | ($0.00263) | ($0.00132) | ($0.00395) |

| SGS & PA | BASE FUEL COMPONENT $/KWH | RIDER A FUEL CHARGE $/KWH | RIDER B EMF $/KWH | TOTAL FUEL RATE $/KWH |
|---|---|---|---|---|
| PRESENT | $0.02115 | $0.00000 | $0.00014 | $0.02129 |
| PROPOSED | $0.02115 | ($0.00262) | ($0.00118) | $0.01735 |
| CHANGE | $0.00000 | ($0.00262) | ($0.00132) | ($0.00394) |

| LGS | BASE FUEL COMPONENT $/KWH | RIDER A FUEL CHARGE $/KWH | RIDER B EMF $/KWH | TOTAL FUEL RATE $/KWH |
|---|---|---|---|---|
| PRESENT | $0.02098 | $0.00000 | $0.00014 | $0.02112 |
| PROPOSED | $0.02098 | ($0.00259) | ($0.00117) | $0.01722 |
| CHANGE | $0.00000 | ($0.00259) | ($0.00131) | ($0.00390) |

NOTES

( ) DENOTES NEGATIVE VALUE

**DOMINION ENERGY NORTH CAROLINA**
**TOTAL FUEL COST LEVEL - PRESENT AND PROPOSED**
**TO BE EFFECTIVE FEBRUARY 1, 2021**

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| NC JURISDICTION | BASE FUEL COMPONENT $/KWH | RIDER A FUEL CHARGE $/KWH | RIDER B EMF $/KWH | TOTAL FUEL RATE $/KWH |
| PRESENT | $0.02092 | $0.00000 | $0.00013 | $0.02105 |
| PROPOSED | $0.02092 | ($0.00254) | ($0.00117) | $0.01721 |
| CHANGE | $0.00000 | ($0.00254) | ($0.00130) | ($0.00384) |
| RESIDENTIAL | BASE FUEL COMPONENT $/KWH | RIDER A FUEL CHARGE $/KWH | RIDER B EMF $/KWH | TOTAL FUEL RATE $/KWH |
| PRESENT | $0.02118 | $0.00000 | $0.00014 | $0.02132 |
| PROPOSED | $0.02118 | ($0.00263) | ($0.00118) | $0.01737 |
| CHANGE | $0.00000 | ($0.00263) | ($0.00132) | ($0.00395) |
| SGS & PA | BASE FUEL COMPONENT $/KWH | RIDER A FUEL CHARGE $/KWH | RIDER B EMF $/KWH | TOTAL FUEL RATE $/KWH |
| PRESENT | $0.02115 | $0.00000 | $0.00014 | $0.02129 |
| PROPOSED | $0.02115 | ($0.00262) | ($0.00118) | $0.01735 |
| CHANGE | $0.00000 | ($0.00262) | ($0.00132) | ($0.00394) |
| LGS | BASE FUEL COMPONENT $/KWH | RIDER A FUEL CHARGE $/KWH | RIDER B EMF $/KWH | TOTAL FUEL RATE $/KWH |
| PRESENT | $0.02098 | $0.00000 | $0.00014 | $0.02112 |

**DOMINION ENERGY NORTH CAROLINA**
**TOTAL FUEL RECOVERY**
**TWELVE MONTHS ENDED JUNE 30, 2020**
**TO BE EFFECTIVE FEBRUARY 1, 2021**

| | (1) | (2) | (3) | (4) | (5) | (6) |
|---|---|---|---|---|---|---|
| CUSTOMER CLASS | SALES(KWH) | BASE FUEL COMPONENT | FUEL COST RIDER A | EMF RIDER B | TOTAL | TOTAL REVENUE |
| | | (A) | (B) | (C) | (2) + (3) + (4) | (1) x (5) |
| RESIDENTIAL | 1,597,301,652 | $0.02118 | ($0.00263) | ($0.00118) | $0.01737 | $27,745,130 |
| SGS & PA | 655,330,488 | $0.02115 | ($0.00262) | ($0.00118) | $0.01735 | $11,369,984 |
| LGS | 651,610,836 | $0.02098 | ($0.00259) | ($0.00117) | $0.01722 | $11,220,739 |
| SCHEDULE NS | 838,113,978 | $0.02036 | ($0.00227) | ($0.00115) | $0.01694 | $14,197,651 |
| 6VP | 246,776,422 | $0.02065 | ($0.00281) | ($0.00113) | $0.01671 | $4,123,634 |
| OUTDOOR LIGHTING | 25,583,952 | $0.02118 | ($0.00263) | ($0.00118) | $0.01737 | $444,393 |
| TRAFFIC | 414,028 | $0.02118 | ($0.00263) | ($0.00118) | $0.01737 | $7,192 |
| TOTAL | 4,015,131,356 | | | | | $69,108,722 |

| | SALES(KWH) | BASE FUEL COMPONENT | FUEL COST RIDER A | EMF RIDER B | TOTAL | TOTAL REVENUE |
|---|---|---|---|---|---|---|
| | | | | | (2) + (3) + (4) | (1) x (5) |
| NORTH CAROLINA JURISDICTION | 4,015,131,356 | $0.02092 | ($0.00254) | ($0.00117) | $0.01721 | $69,100,411 |

| | SALES(KWH) | PRESENT TOTAL RATE | PROPOSED TOTAL RATE | TOTAL CHANGE | TOTAL REVENUE CHANGE |
|---|---|---|---|---|---|
| | | | | (3) - (2) | (4) x (1) |
| NORTH CAROLINA JURISDICTION REVENUE CHANGE | 4,015,131,356 | $0.02105 | $0.01721 | ($0.00384) | ($15,418,104) |

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 | -0.263¢/kWh |
| Schedule 1DF | Residential | -0.263¢/kWh |
| Schedule 1P | Residential | -0.263¢/kWh |
| Schedule 1T | Residential | -0.263¢/kWh |
| Schedule 1W | Residential | -0.263¢/kWh |
| Schedule 5 | SGS & Public Authority | -0.262¢/kWh |
| Schedule 5C | SGS & Public Authority | -0.262¢/kWh |
| Schedule 5P | SGS & Public Authority | -0.262¢/kWh |
| Schedule 7 | SGS & Public Authority | -0.262¢/kWh |
| Schedule 30 | SGS & Public Authority | -0.262¢/kWh |
| Schedule 42 | SGS & Public Authority | -0.262¢/kWh |
| Schedule 6C | Large General Service | -0.259¢/kWh |
| Schedule 6P | Large General Service | -0.259¢/kWh |
| Schedule 6L | Large General Service | -0.259¢/kWh |
| Schedule 10 | Large General Service | -0.259¢/kWh |
| Schedule 26 | Outdoor Lighting | -0.263¢/kWh |
| Schedule 30T | Traffic Control | -0.263¢/kWh |
| Schedule 6VP | 6VP | -0.281¢/kWh |
| Schedule NS Tier 2-Type A and Tier 3 Energy Charges | Schedule NS | -0.227¢/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 | -0.118¢/kWh |
| Schedule 1DF | Residential | -0.118¢/kWh |
| Schedule 1P | Residential | -0.118¢/kWh |
| Schedule 1T | Residential | -0.118¢/kWh |
| Schedule 1W | Residential | -0.118¢/kWh |
| Schedule 5 | SGS & Public Authority | -0.118¢/kWh |
| Schedule 5C | SGS & Public Authority | -0.118¢/kWh |
| Schedule 5P | SGS & Public Authority | -0.118¢/kWh |
| Schedule 7 | SGS & Public Authority | -0.118¢/kWh |
| Schedule 30 | SGS & Public Authority | -0.118¢/kWh |
| Schedule 42 | SGS & Public Authority | -0.118¢/kWh |
| Schedule 6C | Large General Service | -0.117¢/kWh |
| Schedule 6P | Large General Service | -0.117¢/kWh |
| Schedule 6L | Large General Service | -0.117¢/kWh |
| Schedule 10 | Large General Service | -0.117¢/kWh |
| Schedule 26 | Outdoor Lighting | -0.118¢/kWh |
| Schedule 30T | Traffic Control | -0.118¢/kWh |
| Schedule 6VP | 6VP | -0.113¢/kWh |
| Schedule NS Tier 2-Type A and Tier 3 Energy Charges | Schedule NS | -0.115¢/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.



Superseding Filing Effective For Usage On and After 02-01-20. This Filing Effective For Usage On and After 02-01-21 Through and Including 01-31-2022.

**VERIFICATION**

**NCUC Docket No. E-22, Sub 590**

I, Corynne S. Arnett, Senior Vice President, Regulatory Affairs and Customer Experience, 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.

Corynne S. Arnett

Corynne S. Arnett

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

The foregoing instrument was sworn to and acknowledged before me this 10th day of August 2020.

Denise Ann Tunstall

Notary Public

My registration number is 7707756 and my commission expires: April 30, 2024

DENISE ANN TUNSTALL
NOTARY PUBLIC
REG # 7707756
MY COMMISSION EXPIRES 4/30/24
COMMONWEALTH OF VIRGINIA