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June 14, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Progress, LLC's Fuel Charge Adjustment Proceeding Docket No. E-2, Sub 1292

Dear Ms. Dunston:

Enclosed for filing with the North Carolina Utilities Commission ("NCUC" or the "Commission") is the Application of Duke Energy Progress, LLC ("DEP") pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 relating to the fuel charge adjustments for electric utilities, together with the direct testimony, exhibits, and workpapers of Dana M. Harrington, direct testimony and exhibits of Matthew L. Cameron, Tom Ray, John A. Verderame, direct testimony of Bryan P. Walsh, and David B. Johnson containing the information required in NCUC Rule R8-55.

Certain information contained in the exhibits of Mr. Verderame and Mr. Ray is a trade secret, and confidential, proprietary, and commercially sensitive information. For that reason, it is being filed under seal pursuant to N.C. Gen. Stat. § 132-1.2 and should be protected from disclosure. Parties to the docket may contact the Company to obtain copies pursuant to an appropriate confidentiality agreement.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Jack E. Jirak

Enclosure
cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's Fuel Charge Adjustment Proceeding, in Docket No. E-2, Sub 1292, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the parties of record.

This the 14th day of June, 2022.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	))))	**DUKE ENERGY PROGRESS LLC'S APPLICATION**

Duke Energy Progress, LLC ("DEP," "Company" or "Applicant"), pursuant to North Carolina General Statutes ("N.C. Gen. Stat.") § 62-133.2 and North Carolina Utilities Commission ("NCUC" or the "Commission") Rule R8-55, hereby makes this Application to adjust the fuel and fuel-related cost component of its electric rates. In support thereof, the Applicant respectfully shows the Commission the following:

1. The Applicant's general offices are located at 410 South Wilmington Street, Raleigh, North Carolina, and its mailing address is:

Duke Energy Progress, LLC
P. O. Box 1551
Raleigh, North Carolina 27602

2. The name and address of Applicant's attorneys are:

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

3. NCUC Rule R8-55 provides that the Commission shall schedule annual hearings pursuant to N.C. Gen. Stat. § 62-133.2 in order to review changes in the cost of fuel and fuel-related costs since the last general rate case for each utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service. Rule R8-55 schedules an annual cost of fuel and fuel-related costs adjustment hearing for DEP and requires that the Company use a test period of 12 months ended March 31. Therefore, the test period used in this Application for these proceedings is April 1, 2021 – March 31, 2022 ("test period").

4. In Docket No. E-2, Sub 1272, DEP's last fuel case, the Commission approved the following fuel and fuel-related costs factors (excluding the Experience Modification Factor ("EMF") and regulatory fee):

Residential	2.126¢ per kWh
Small General Service	2.111¢ per kWh
Medium General Service	2.169¢ per kWh
Large General Service	2.019¢ per kWh
Lighting	1.682¢ per kWh

5. In this Application, DEP proposes fuel and fuel-related costs factors (excluding EMF and regulatory fee) of:

Residential	2.856¢ per kWh
Small General Service	3.046¢ per kWh
Medium General Service	2.547¢ per kWh
Large General Service	2.227¢ per kWh
Lighting	3.207¢ per kWh

In addition, these factors should be adjusted for the EMF by an increment/(decrement) (excluding regulatory fee) of:

Residential	0.489¢ per kWh
Small General Service	0.371¢ per kWh
Medium General Service	0.540¢ per kWh
Large General Service	0.756¢ per kWh
Lighting	0.776¢ per kWh

This results in composite fuel and fuel-related costs factors (excluding regulatory fee) of:

Residential	3.345¢ per kWh
Small General Service	3.417¢ per kWh
Medium General Service	3.087¢ per kWh
Large General Service	2.983¢ per kWh
Lighting	3.983¢ per kWh

The new fuel factors should become effective for service on or after December 1, 2022.

6. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Matthew L. Cameron, Tom Ray, John A. Verderame, Bryan P. Walsh, and the testimony, exhibits, and workpapers of Dana M. Harrington, which are being filed simultaneously with this Application and incorporated herein by reference.

7. For comparison, in accordance with Rule R8-55(d)(1) and R8-55(e)(3),

base fuel and fuel-related costs factors were also calculated based on the most recent North American Electric Reliability Corporation ("NERC") five-year national average nuclear capacity factor of 93.49% using projected billing period sales, and based on the proposed nuclear capacity factor of 94.05% using normalized test period sales. These base fuel and fuel-related costs factors are:

	NERC Average	Normalized Sales
Residential	3.356¢ per kWh	3.323¢ per kWh
Small General Service	3.430¢ per kWh	3.312¢ per kWh
Medium General Service	3.095¢ per kWh	3.071¢ per kWh
Large General Service	2.988¢ per kWh	3.031¢ per kWh
Lighting	4.006¢ per kWh	4.314¢ per kWh

WHEREFORE, Duke Energy Progress, LLC requests that the Commission issue an order approving composite fuel and fuel-related costs factors (excluding regulatory fee) of:

Residential	3.345¢ per kWh
Small General Service	3.417¢ per kWh
Medium General Service	3.087¢ per kWh
Large General Service	2.983¢ per kWh
Lighting	3.983¢ per kWh

Respectfully submitted this 14th day of June, 2022.

By: Jack Jirak

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ATTORNEYS FOR DUKE ENERGY PROGRESS, LLC

VERIFICATION

STATE OF NORTH CAROLINA)
)   DOCKET NO. E-2, SUB 1292
COUNTY OF MECKLENBURG)

Dana M. Harrington, being first duly sworn, deposes and says:

That she is Rates and Regulatory Strategy Manager for Duke Energy Progress, LLC; that she has read the foregoing Application and knows the contents thereof; that the same is true except as to the matters stated therein on information and belief; and as to those matters, she believes it to be true.

Dana M. Harrington

Dana M. Harrington

Signed and sworn to before me this day by Dana M Harrington
Name of principal

Date: June 13, 2022

DINA M HAGSTROM
NOTARY
PUBLIC
MECKLENBURG COUNTY, N.C.
(Official Seal)

Official Signature of Notary

Dina M Hagstrom, Notary Public
Notary's printed or typed name

My commission expires: Aug 19 2024

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF DANA M. HARRINGTON FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dana M. Harrington, and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Rates and Regulatory Strategy Manager supporting both Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Companies").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Psychology with Honors from the University of North Carolina at Chapel Hill and I am a certified public accountant licensed in the State of North Carolina. I began my accounting career in 2005 with Greer and Walker, LLC as a tax accountant and later a staff auditor. From 2007 until 2010 I was an Accounting Analyst with Duke Energy in the Finance organization. In 2010, I joined the Rates Department as a Lead Rates Analyst where I spent eight years before being promoted to the position of Rates and Regulatory Strategy Manager. I have served in the Rates Manager capacity since 2019.

Q. HAVE YOU PREVIOUSLY TESTIFIED OR SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I testified in DEP's 2019 fuel proceeding under Docket No. E-2, Sub 1204 and filed direct and supplemental testimony in DEP's 2020 and 2021 fuel proceedings under Docket Nos. E-2, Sub 1250 and E-2, Sub 1272, respectively.

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DEP?

A. Yes. Duke Energy Progress' books of account follow the uniform classification of accounts prescribed by the Federal Energy Regulatory Commission ("FERC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the information and data required by North Carolina General Statutes ("N.C. Gen. Stat.") § 62-133.2(c) and (d) and Commission Rule R8-55, as set forth in Harrington Exhibits 1 through 6, along with supporting workpapers. The test period used in supplying this information is the period of April 1, 2021 through March 31, 2022 ("test period"), and the billing period is December 1, 2022 through November 30, 2023 ("billing period").

Q. WHAT IS THE SOURCE OF THE ACTUAL INFORMATION AND DATA FOR THE TEST PERIOD?

A. Actual test period kilowatt hour ("kWh") generation, kWh sales, fuel-related revenues, and fuel-related expenses were taken from the Company's books and records. These books, records, and reports of the Company are subject to review by the regulatory agencies that regulate the Company's electric rates.

In addition, independent auditors perform an annual audit to provide assurance that, in all material respects, internal accounting controls are operating effectively and the Company's financial statements are accurate.

Q. WERE HARRINGTON EXHIBITS 1 THROUGH 6 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes, these exhibits were prepared by me and consist of the following:

- Exhibit 1: Summary Comparison of Fuel and Fuel-Related Costs Factors.
- Exhibit 2, Schedule 1: Fuel and Fuel-Related Costs Factors - reflecting a 94.05% proposed nuclear capacity factor and projected billing period megawatt hour

("MWh") sales.

- Exhibit 2, Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 94.05% proposed nuclear capacity factor and normalized test period MWh sales.
- Exhibit 2, Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting an 93.49% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for comparable units and projected billing period MWh sales.
- Exhibit 3, Page 1: Calculation of the Proposed Composite Experience Modification Factor ("EMF") rate.
- Exhibit 3, Page 2: Calculation of the EMF for residential customers.
- Exhibit 3, Page 3: Calculation of the EMF for small general service customers.
- Exhibit 3, Page 4: Calculation of the EMF for medium general service customers.
- Exhibit 3, Page 5: Calculation of the EMF for large general service customers.
- Exhibit 3, Page 6: Calculation of the EMF for lighting customers.
- Exhibit 4: Normalized Test Period MWh Sales, Fuel and Fuel-Related Revenue, Fuel and Fuel-Related Expense, and System Peak.
- Exhibit 5: Nuclear Capacity Ratings.
- Exhibit 6, Report 1: March 2022 Monthly Fuel Report, as required by NCUC Rule R8-52.
- Exhibit 6, Report 2: March 2022 Monthly Base Load Power Plant Performance Report, as required by NCUC Rule R8-53.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON HARRINGTON EXHIBIT 1.

A. Harrington Exhibit 1 presents a summary of fuel and fuel-related cost factors, which include: the currently approved fuel and fuel-related cost factors, the projected fuel and fuel-related cost factors using the NERC five-year national weighted average capacity factor with projected billing period sales, the projected fuel and fuel-related cost factors using the proposed capacity factor with normalized test period sales, and the proposed fuel and fuel-related cost factors using the proposed capacity factor with projected billing period sales.

Q. WHAT FUEL AND FUEL-RELATED COST FACTORS DOES DEP PROPOSE FOR INCLUSION IN RATES FOR THE BILLING PERIOD?

A. The Company proposes that the fuel and fuel-related costs factors shown in the table below be reflected in rates during the billing period. The factors that DEP proposes in this proceeding utilize a 94.05% nuclear capacity factor as testified to by Company Witness Ray. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Harrington Exhibit 1 in cents per kWh, are:

Description	Residential cents/kWh	Small General Service cents/kWh	Medium General Service cents/kWh	Large General Service cents/kWh	Lighting cents/kWh
Total adjusted Fuel and Fuel-Related Costs Factors	2.856	3.046	2.547	2.227	3.207
EMF Increment/(Decrement)	0.489	0.371	0.540	0.756	0.776
Proposed Net Fuel and Fuel-Related Costs Factors	3.345	3.417	3.087	2.983	3.983

Q. WHAT IS THE IMPACT TO CUSTOMERS' BILLS IF THE PROPOSED FUEL AND FUEL-RELATED COST FACTORS ARE APPROVED BY THE COMMISSION?

A. If the proposed fuel and fuel-related cost factors are approved, there will be an increase of 7.8%, on average, in customers' bills. The table below shows both the proposed and existing fuel and fuel-related cost factors (excluding regulatory fee).

Description	Residential cents/kWh	Small General Service cents/kWh	Medium General Service cents/kWh	Large General Service cents/kWh	Lighting cents/kWh
Proposed Net Fuel and Fuel-Related Costs Factors	3.345	3.417	3.087	2.983	3.983
Approved Net Fuel and Fuel-Related Costs Factors	2.371	2.297	2.404	2.527	2.018

Q. HOW DOES DEP DEVELOP THE FUEL FORECASTS FOR ITS GENERATING UNITS?

A. For this filing, DEP used an hourly dispatch model in order to generate its fuel forecasts. This hourly dispatch model considers the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities. In addition, the model dispatches DEP's and DEC's generation resources with the joint dispatch, which optimizes the generation fleets of DEP and DEC combined.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON HARRINGTON EXHIBIT 2, SCHEDULES 1, 2, AND 3 INCLUDING THE NUCLEAR CAPACITY FACTORS.

A. Exhibit 2 is divided into three schedules. Schedule 1 presents the prospective fuel and fuel-related costs. The calculation uses the nuclear capacity factor of 94.05%, as explained in Company Witness Ray's testimony, and provides the projected MWh sales for the billing period on which system generation and costs are based. Schedule 2 also uses the proposed nuclear capacity factor of 94.05% but against normalized test period kWh sales, as prescribed by NCUC Rule R8-55(e)(3), which requires the use of the methodology adopted by the Commission in the Company's most recent general rate case (Docket No. E-2, Sub 1219).

The nuclear capacity factor used on Schedule 3 is prescribed in NCUC Rule R8-55(d)(1). The NERC five-year national weighted average nuclear capacity factor is 93.49%. This capacity factor is based on the 2016 through 2020 data reported in the NERC's Generating Unit Statistical Brochure ("NERC Brochure") for units comparable to DEP's nuclear fleet. Schedule 3 also uses the projected billing period kWh sales as required by NCUC Rule R8-55(d)(1).

Page 2 of Exhibit 2, Schedules 1, 2, and 3, presents the calculation of the proposed fuel and fuel-related cost factors by customer class resulting from the allocation of renewable and qualifying facility capacity costs to the North Carolina retail jurisdiction and by customer class on the basis of calendar year 2021 production plant. The production plant allocator was approved for use in DEP's most recent general rate case.

Page 3 of Exhibit 2, Schedules 1, 2, and 3 shows the allocation of system fuel costs to the North Carolina retail jurisdiction, and the calculation of DEP's proposed fuel and fuel-related cost factors for the residential, small general service, medium general service, large general service, and lighting classes (excluding regulatory fee), using the uniform percentage average bill adjustment method.

Q. PLEASE SUMMARIZE THE METHOD USED TO ADJUST KWH GENERATION IN HARRINGTON EXHIBIT 2, SCHEDULES 2 AND 3.

A. As used in DEP's most recent general rate case, and for the purposes of this filing, Harrington Exhibit 2 Schedule 2 adjusts the coal generation produced by the dispatch model to account for the difference between forecasted generation and normalized test period generation.

On Exhibit 2, Schedule 3, which is based on the NERC capacity factor, DEP increased the level of coal generation produced by the dispatch model to account for the decrease in nuclear generation. The decrease in nuclear generation results from assuming a 93.49% NERC nuclear capacity factor compared to the proposed 94.05% nuclear capacity factor.

Q. HOW ARE PROJECTED FUEL AND FUEL-RELATED COSTS ALLOCATED?

A. System fuel and fuel-related costs are allocated to the North Carolina retail jurisdiction based on jurisdictional sales. Costs are further allocated among customer classes using the uniform percentage average bill adjustment methodology in this fuel proceeding as adopted in DEP's 2021 fuel and fuel-related cost recovery proceeding under Docket No. E-2, Sub 1272.

System renewable and qualifying facility capacity costs as described in subsections (5), (6) and (10) of N.C. Gen. Stat. § 62-133.2(a1), are allocated to the NC retail jurisdiction and among customer classes based on the 2021 production plant allocator.

Q. PLEASE EXPLAIN THE CALCULATION OF THE UNIFORM PERCENTAGE AVERAGE BILL ADJUSTMENT METHOD SHOWN ON HARRINGTON EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3.

A. Harrington Exhibit 2, Page 3 of Schedule 1 shows DEP's proposed fuel and fuel-related cost factors for the residential, small general service, medium general service, large general service, and lighting classes (excluding regulatory fee). The uniform bill percentage increase of 7.8% was calculated by dividing the fuel and fuel-related cost increase of approximately $302.3 million for the North Carolina retail jurisdiction by the normalized annual North Carolina retail revenues at the existing rates of approximately $3.9 billion. The cost increase of approximately $302.3 million was determined by comparing the total proposed fuel rate per kWh to the total fuel rate per kWh currently being collected from customers, and multiplying the resulting increase in fuel rate per kWh by projected billing period sales on Schedule 1. The proposed fuel rate per kWh equals the sum of the rate necessary to recover projected billing period fuel costs and the proposed composite EMF increment as computed on Harrington Exhibit 3, Page 1. Harrington Exhibit 2, Page 3 of Schedules 2 and 3 uses the same calculation, but with the methodology as prescribed by NCUC Rule R8-55(e)(3) and NCUC Rule R8-55(d)(1), respectively.

Q. HOW ARE SPECIFIC FUEL AND FUEL-RELATED COST FACTORS FOR EACH CUSTOMER CLASS DERIVED FROM THE UNIFORM PERCENT ADJUSTMENT COMPUTED ON HARRINGTON EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. On each of Harrington Exhibit 2, Page 3 of Schedules 1, 2, and 3, the equal percent increase for each customer class is applied to current annual revenues by customer class to determine a revenue increase for each customer class. The revenue increase is divided by kwh sales for each class to derive a cents/kWh increase. The sales basis for deriving a cents/kWh increase by class on Schedules 1 and 3 is projected billing period sales and the sales basis for deriving a cents/kWh increase by class on Schedule 2 is normalized test period sales. The current total fuel and fuel-related cost factors for each class are adjusted by the proposed cents/kWh increase to get the proposed total fuel and fuel-related cost factors. The proposed total fuel factors are then separated into the prospective and EMF components by subtracting the EMF components for each customer class as computed on Harrington Exhibit 3, Pages 2, 3, 4, 5, and 6 to derive the prospective rate component for each customer class. Presentation of the projected fuel and fuel-related cost factors and the projected EMF increments are shown on Harrington Exhibit 2, Page 2 of Schedules 1, 2, and 3.

Q. DID YOU DETERMINE THAT DEP'S ANNUAL CHANGE IN THE AGGREGATE AMOUNT OF THE COSTS IDENTIFIED IN SUBSECTIONS (4), (5), (6), (10) AND (11) OF N.C. GEN. STAT. § 62-133.2(A1) DID NOT EXCEED 2.5% OF ITS NC RETAIL GROSS REVENUES FOR 2021, AS REQUIRED BY N.C. GEN. STAT. § 62-133.2(A2)?

A. Yes. The Company's analysis shows that the annual change in the costs recoverable under the relevant sections of the statute was an increase but the increase did not exceed 2.5% of DEP's North Carolina Retail gross revenues for calendar year 2021.

Q. HARRINGTON EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD (OVER)/UNDER RECOVERY BALANCE AND THE PROPOSED EMF RATE. HOW WAS THIS CALCULATED?

A. DEP system fuel and fuel-related costs incurred were first allocated to the North Carolina retail jurisdiction based on North Carolina's retail billed sales as a percentage of system billed sales adjusted to include South Carolina Distributed Energy Resource Program estimated net metered generation. The adjustment to system billed sales yields a smaller share of system fuel and fuel-related costs allocated to the North Carolina retail jurisdiction than without the adjustment. The North Carolina retail share of system fuel and fuel-related costs were allocated among customer classes using the uniform percentage average bill adjustment method consistent with DEP's previous annual fuel proceeding.

DEP system purchased power capacity costs from renewables and qualifying facilities were allocated to the North Carolina retail jurisdiction and among customer classes based on production plant allocators from DEP's 2021 cost of service study.

The test period (over)/under collection was determined each month by comparing the actual fuel revenues collected from each class to actual costs incurred by class.

Q. HOW DID ACTUAL FUEL EXPENSES COMPARE WITH FUEL REVENUE DURING THE TEST PERIOD?

A. Harrington Exhibit 3, Page 1 demonstrates that, for the test period, the Company experienced a net under-recovery of approximately $244.3 million for the combined customer classes of the North Carolina retail jurisdiction.

The Company typically experiences some amount of (over)/under recovery of fuel costs during the test period. The EMF provision of fuel rates was established to address the differences between fuel revenues realized and fuel costs incurred during a test period. Beginning around June 2021 the Company experienced an unexpected increase in fuel commodity costs, and continues to see actual fuel costs out-pace projected costs. This trend is further described in the direct testimony of Witness Verderame. For the test period, fuel revenues collected by DEP were materially less than the fuel costs incurred, resulting in a large under collection of costs, which is reflected in DEP's proposed EMF rates.

Q. HAS THE COMPANY MADE ANY COST ADJUSTMENTS TO THE TWELVE-MONTH TEST PERIOD UNDER-COLLECTION OF FUEL AND FUEL-RELATED COSTS THAT WERE REMITTED ON THE MONTHLY

FUEL REPORTS?

A. Yes. As explained in the Supplemental Testimony of Dana Harrington in Docket E-2, Sub 1272, in the month of July 2021, it was discovered that due to billing system complexity for real-time pricing, one Industrial Large General Service – Real-Time Pricing ("LGS-RTP") customer's kWh usage for the months of June 2020 through June 2021 were not recognized on system-generated kWh sales reports. Kilowatt hour sales and calculations based on kWh sales were revised to include the missing sales, including a June 2021 adjustment to true-up the EMF on Harrington Exhibit 3 Pages 1-6.

Second, in the month of February 2022, DEP calculated a June 2021 through October 2021 net true-up of South Carolina Distributed Energy Resource Program net energy metering marginal fuel costs and benefits. Respectively, DEP calculated and included the corresponding net adjustment $(551) to the DEP North Carolina test period under-collection of fuel and fuel-related costs on Harrington Exhibit 3 Pages 1-6.

Q. IS THE COMPANY PROPOSING ANY OTHER COST ADJUSTMENTS TO THE TWELVE-MONTH TEST PERIOD UNDER-COLLECTION BEING REQUESTED FOR COST RECOVERY IN THIS PROCEEDING THAT WERE NOT REMITTED ON THE MONTHLY FUEL REPORTS?

A. Yes. NCUC Rule R8-55(d)(3) allows the Company to update the fuel and fuel-related cost recovery balance up to thirty (30) days prior to the hearing. The Company elected this option and supplemented the proposed fuel rates in Docket No. E-2, Sub 1272 to include the under-collection experienced by the Company of $38,080,743 during the months of April, May, and June 2021. That request was approved by the Commission in the rates set forth in Docket No. E-2, Sub 1272; therefore, that under-collected amount has been excluded from the request for recovery in this proceeding.

Finally, consistent with the approach approved by the Commission in Docket E-2, Sub 1204, the Company is proposing to recover the related component of liquidated damages associated with the sale of by-products that were incurred in the test period on a cash basis rather than an accrual basis. To achieve this result, the North Carolina retail share of associated liquidated damages accrued during the test period has been excluded from the test period under-collection and the North Carolina retail share of the associated liquidated damages cash payment made during the test period has been included. These adjustments of approximately \$(1.4) million and \$5.6 million, respectively, are presented on Harrington Exhibit 3, Page 1 and further itemized by customer class on Harrington Exhibit 3, Pages 2 through 6.

For additional clarity, please note that the prospective North Carolina retail portion of the associated liquidated damages cash payment to be made during the billing period of approximately \$5.2 million has also been included in projected billing period costs consistent with the approach approved by the Commission in Docket E-2, Sub 1272.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON HARRINGTON EXHIBIT 4.

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Harrington Exhibit 4 presents test period actual MWh sales, the customer growth MWh adjustment, and the weather MWh adjustment. Test period MWh sales were normalized for weather using a 30-year period, consistent with the methodology utilized in DEP's most recent general rate case. Customer growth was determined using regression analysis for residential, small general service, and lighting classes, and a customer-by-customer analysis for medium and large general service customers. Finally, Harrington Exhibit 4 shows the prior calendar year end peak demand for the system and for North Carolina Retail customer classes.

Q. PLEASE IDENTIFY WHAT IS SHOWN ON HARRINGTON EXHIBIT 5.

A. Harrington Exhibit 5 presents the capacity ratings for each of DEP's nuclear units, in compliance with Rule R8-55(e)(12).

Q. DO YOU BELIEVE DEP'S FUEL AND FUEL-RELATED COSTS INCURRED IN THE TEST YEAR ARE REASONABLE?

A. Yes. As shown on Harrington Exhibit 6, DEP's test year actual fuel and fuel-related costs were 2.816 cents/kWh. Key factors in DEP's ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio of nuclear, natural gas, coal, and hydro, the capacity factors of its nuclear fleet, and fuel procurement strategies, which mitigate volatility in supply costs. Other key factors include DEP's and DEC's respective expertise in transporting, managing and blending fuels, procuring reagents, and utilizing purchasing synergies of the combined Company, as well as the joint dispatch of DEP's and DEC's generation resources.

Company Witness Walsh discusses the performance of the fossil/hydro/solar fleet, as well as the chemicals that DEP uses to reduce emissions. Company Witness Verderame discusses fossil fuel costs and fossil fuel procurement strategies. Company Witness Cameron discusses nuclear fuel costs and nuclear fuel procurement strategies, and Company Witness Ray discusses the performance of DEP's nuclear generation fleet. The Company's test year capacity factor of 93.99% exceeded the NERC five-year average of 93.49%. Witness Ray provides further details demonstrating the reasonableness and prudence of the Company's actions in connection with the nuclear outages occurring during the test period.

Q. WHAT ARE THE KEY DRIVERS IMPACTING THE PROPOSED FUEL AND FUEL-RELATED COST FACTORS?

A. For the billing period, the drivers propelling the fuel rate increase include: the increased cost of natural gas anticipated for the prospective billing period and the request for collection of an approximate $210.4 million under-collection in proposed rates compared to the $113.1 million under-collection included in existing rates. The current year under-collection was also driven primarily by escalating natural gas prices.

Q. HAS THE COMPANY FILED WORKPAPERS SUPPORTING THE CALCULATIONS, ADJUSTMENTS, AND NORMALIZATIONS AS REQUIRED BY NCUC RULE R8-55(E)(11)?

A. Yes. Working papers supporting the calculations, adjustments, and normalizations utilized to derive the proposed fuel factors are included with this filing.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Summary Comparison of Fuel and Fuel-Related Cost Factors
Twelve Months Ended March 31, 2022
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Exhibit 1

Line No.	Description	Reference	Residential cents/kWh	Small General Service cents/kWh	Medium General Service cents/kWh	Large General Service cents/kWh	Lighting cents/kWh
	Current Fuel and Fuel-Related Cost Factors (Approved Fuel Rider Docket No. E-2, Sub 1272)						
1	Approved Fuel and Fuel-Related Costs Factors	Input	2.126	2.111	2.169	2.019	1.682
2	EMF Increment / (Decrement)	Input	0.245	0.186	0.235	0.508	0.336
3	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
4	Approved Net Fuel and Fuel-Related Costs Factors	Sum	2.371	2.297	2.404	2.527	2.018
	Other Fuel and Fuel-Related Cost Factors						
5	NERC Capacity Factor of 93.49% with Projected Billing Period MWh Sales	Exh 2 Sch 3 pg 3	3.356	3.430	3.095	2.988	4.006
6	Proposed Nuclear Capacity Factor of 94.05% with Normalized Test Period MWh	Exh 2 Sch 2 pg 3	3.323	3.312	3.071	3.031	4.314
	Proposed Fuel and Fuel-Related Cost Factors using Proposed Nuclear Capacity Factor of 94.05% with Projected Billing Period MWh Sales						
7	Fuel and Fuel-Related Costs excluding Purchased Capacity	Exh 2 Sch 1 pg 2	2.720	2.903	2.441	2.153	3.207
8	Renewable and Qualifying Facilities Purchased Power Capacity	Exh 2 Sch 1 pg 2	0.136	0.143	0.106	0.074	-
9	Total adjusted Fuel and Fuel-Related Costs Factors	Sum	2.856	3.046	2.547	2.227	3.207
10	EMF Increment/(Decrement)	Exh 2 Sch 1 pg 2	0.489	0.371	0.540	0.756	0.776
11	EMF Interest Decrement, if applicable	n/a	-	-	-	-	-
12	Proposed Net Fuel and Fuel-Related Costs Factors	Exh 2 Sch 1 pg 2	3.345	3.417	3.087	2.983	3.983

Note: The above rates do not include state regulatory fees.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.05% with Projected Billing Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 3-4	29,601,651	0.5952	$ 176,202,941
2	Coal	Workpaper 3 - 4	9,087,592	3.8657	351,295,882
3	Gas - CT and CC	Workpaper 3 - 4	19,494,222	3.7995	740,683,337
4	Reagents & Byproducts	Workpaper 5	-		47,259,477
5	Total Fossil	Sum of Lines 2 - 4	28,581,814		1,139,238,696
6	Hydro	Workpaper 3	667,442		-
7	Net Pumped Storage		-		-
8	Total Hydro	Sum of Lines 6 - 7	667,442		-
9	Utility Owned Solar Generation	Workpaper 3	264,499		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	59,115,406		1,315,441,637
11	Purchases	Workpaper 3 - 4	10,294,418		547,458,242
12	JDA Savings Shared	Workpaper 6	-		(37,582,671)
13	Total Purchases	Sum of Lines 11 - 12	10,294,418		509,875,571
14	Total Generation and Purchases	Line 10 + Line 13	69,409,824		1,825,317,208
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(5,502,977)		(213,736,707)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(2,364,858)		-
					-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16	-		$ 1,611,580,501
18	Projected System MWh Sales for Fuel Factor	Workpaper 3	61,541,989		61,541,989
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 /Line 18 / 10			2.619

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.05% with Projected Billing Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Retail Projected Billing Period MWh Sales	Workpaper 8	16,637,596	1,797,603	10,360,942	9,189,937	379,481	38,365,559
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 23,896,105
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						46,050,571
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 69,946,676
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Workpaper 14						61.54%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 43,045,531
7	Production Plant Allocation Factors	Workpaper 14	52.73%	5.99%	25.52%	15.77%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,696,026	$ 2,577,085	$ 10,984,273	$ 6,788,147	$ -	$ 43,045,531
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.136	0.143	0.106	0.074	-	0.112
	Summary of Total Rate by Class		cents/kWh	cents/kWh	cents/kWh	cents/kWh	cents/kWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.720	2.903	2.441	2.153	3.207	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.136	0.143	0.106	0.074	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.856	3.046	2.547	2.227	3.207	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.489	0.371	0.540	0.756	0.776	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	3.345	3.417	3.087	2.983	3.983	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.05% with Projected Billing Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Rate Class	NC Retail Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1272 cents/kWh	Proposed Total Fuel Rate (including renewables and EMF) cents/kWh
		A	B	C	D	E	F	G
		Workpaper 8	Workpaper 12	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential	16,637,596	$ 2,075,916,528	$ 162,025,522	7.8%	0.974	2.371	3.345
2	Small General Service	1,797,603	257,917,886	20,130,520	7.8%	1.120	2.297	3.417
3	Medium General Service	10,360,942	907,180,740	70,805,560	7.8%	0.683	2.404	3.087
4	Large General Service	9,189,937	536,849,788	41,901,187	7.8%	0.456	2.527	2.983
5	Lighting	379,481	95,551,608	7,457,814	7.8%	1.965	2.018	3.983
6	NC Retail	38,365,559	$ 3,873,416,550	$ 302,320,603				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 8	$ 1,612,342,436
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	69,946,676
9	Adjusted System Other Fuel Costs	Line 7 - Line 8	$ 1,542,395,760
10	NC Retail Allocation % - sales at generation	Workpaper 11	62.74%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 967,699,100
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	43,045,531
13	NC Retail Total Fuel Costs before 2.5% Purchase Power Test	Line 11 + Line 12	$ 1,010,744,631
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 1,010,744,631
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,365,559
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 / 10	2.635
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.557
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19	3.192
	Total Current Composite Fuel Rate - Docket E-2 Sub 1272:		
21	Current composite Fuel Rate cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17	2.106
22	Current composite EMF Rate cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18	0.298
23	Current composite EMF Interest cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21-23	2.404
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	0.788
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,365,559
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$ 302,320,603

Notes:
Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.05% with Normalized Test Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 3-4	29,601,651	0.5952	$	176,202,941
2	Coal	Workpaper 15	9,091,447	3.8657		351,444,903
3	Gas - CT and CC	Workpaper 3-4	19,494,222	3.7995		740,683,337
4	Reagents & Byproducts	Workpaper 4	-			47,259,477
5	Total Fossil	Sum of Lines 2 - 4	28,585,669			1,139,387,717
6	Hydro	Workpaper 3	667,442			-
7	Net Pumped Storage		-			-
8	Total Hydro	Sum of Lines 6 - 7	667,442			-
9	Utility Owned Solar Generation	Workpaper 3	264,499			-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	59,119,261			1,315,590,658
11	Purchases	Workpaper 3 - 4	10,294,418			547,458,242
12	JDA Savings Shared	Workpaper 6	-			(37,582,671)
13	Total Purchases	Sum of Lines 11 - 12	10,294,418			509,875,571
14	Total Generation and Purchases	Line 10 + Line 13	69,413,679			1,825,466,229
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(5,502,977)			(213,736,707)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(2,365,007)			-
						-
17	System Fuel Expense for Fuel Factor	Lines 14 + Line 15 + Line 16	-		$	1,611,729,522
18	Normalized Test Period MWh Sales for Fuel Factor	Exhibit 4	61,545,696			61,545,696
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10				2.619

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.05% with Normalized Test Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Retail Normalized Test Period MWh Sales	Workpaper 9	16,792,596	1,956,415	10,468,785	8,202,098	320,322	37,740,216
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 23,896,105
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						46,050,571
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 69,946,676
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Workpaper 14						61.54%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 43,045,531
7	Production Plant Allocation Factors	Workpaper 14	52.73%	5.99%	25.52%	15.77%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,696,026	$ 2,577,085	$ 10,984,273	$ 6,788,147	$ -	$ 43,045,531
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.135	0.132	0.105	0.083	-	0.114
	Summary of Total Rate by Class		cents/kWh	cents/kWh	cents/kWh	cents/kWh	cents/kWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.699	2.809	2.426	2.192	3.538	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.135	0.132	0.105	0.083	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.834	2.941	2.531	2.275	3.538	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.489	0.371	0.540	0.756	0.776	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	3.323	3.312	3.071	3.031	4.314	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.05% with Normalized Test Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Rate Class		NC Retail Normalized Test Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1272 cents/kWh	Proposed Total Fuel Rate (including renewables and EMF) cents/kWh
			A	B	C	D	E	F	G
			Workpaper 9	Workpaper 12	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential		16,792,596	$ 2,075,916,528	$ 159,789,101	7.7%	0.952	2.371	3.323
2	Small General Service		1,956,415	257,917,886	19,852,661	7.7%	1.015	2.297	3.312
3	Medium General Service		10,468,785	907,180,740	69,828,239	7.7%	0.667	2.404	3.071
4	Large General Service		8,202,098	536,849,788	41,322,830	7.7%	0.504	2.527	3.031
5	Lighting		320,322	95,551,608	7,354,875	7.7%	2.296	2.018	4.314
6	NC Retail		37,740,216	$ 3,873,416,550	$ 298,147,705				
	Total Proposed Composite Fuel Rate:								
7	Adjusted System Total Fuel Costs	Workpaper 9		$ 1,612,491,458					
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2		69,946,676					
9	System Other Fuel Costs	Line 7 - Line 8		$ 1,542,544,781					
10	NC Retail Allocation % - sales at generation	Workpaper 11		61.73%					
11	NC Retail Other Fuel Costs	Line 9 * Line 10		$ 952,212,893					
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2		43,045,531					
13	NC Retail Total Fuel Costs	Line 11 + Line 12		$ 995,258,425					
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 17		0					
15	NC Retail Total Fuel Costs	Line 13 + Line 14		$ 995,258,425					
16	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A		37,740,216					
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10		2.637					
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		0.557					
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1		0.000					
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19		3.194					
	Total Current Composite Fuel Rate - Docket E-2 Sub 1272:								
21	Current composite Fuel Rate cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17		2.106					
22	Current composite EMF Rate cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18		0.298					
23	Current composite EMF Interest cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19		0.000					
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23		2.404					
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24		0.790					
26	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A		37,740,216					
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10		$ 298,147,705					

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
NERC Capacity Factor of 93.49% with Projected Billing Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 2	29,426,308	0.5952	$ 175,159,216
2	Coal	Workpaper 15	9,262,935	3.8657	358,074,064
3	Gas - CT and CC	Workpaper 3 - 4	19,494,222	3.7995	740,683,337
4	Reagents & Byproducts	Workpaper 5	-		47,259,477
5	Total Fossil	Sum of Lines 2 - 4	28,757,157		1,146,016,878
6	Hydro	Workpaper 3	667,442		-
7	Net Pumped Storage		-		-
8	Total Hydro	Sum of Lines 6 - 7	667,442		-
9	Utility Owned Solar Generation	Workpaper 3	264,499		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	59,115,406		1,321,176,094
11	Purchases	Workpaper 3 - 4	10,294,418		547,458,242
12	JDA Savings Shared	Workpaper 6	-		(37,582,671)
13	Total Purchases	Sum of Lines 11- 12	10,294,418		509,875,571
14	Total Generation and Purchases	Line 10 + Line 13	69,409,824		1,831,051,665
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(5,502,977)		(213,736,707)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(2,364,858)		-
					-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16	-		$ 1,617,314,958
18	System MWh Sales for Fuel Factor	Workpaper 3	61,541,989		61,541,989
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10			2.628

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
NERC Capacity Factor of 93.49% with Projected Billing Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Retail Projected Billing Period MWh Sales	Workpaper 8	16,637,596	1,797,603	10,360,942	9,189,937	379,481	38,365,559
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 23,896,105
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						46,050,571
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 69,946,676
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Workpaper 14						61.54%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 43,045,531
7	Production Plant Allocation Factors	Workpaper 14	52.73%	5.99%	25.52%	15.77%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,696,026	$ 2,577,085	$ 10,984,273	$ 6,788,147	$ -	$ 43,045,531
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.136	0.143	0.106	0.074	-	0.112
	Summary of Total Rate by Class		cents/kWh	cents/kWh	cents/kWh	cents/kWh	cents/kWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.731	2.916	2.449	2.158	3.230	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.136	0.143	0.106	0.074	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.867	3.059	2.555	2.232	3.230	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.489	0.371	0.540	0.756	0.776	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	3.356	3.430	3.095	2.988	4.006	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
NERC Capacity Factor of 93.49% with Projected Billing Period MWh Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Line No.	Rate Class	NC Retail Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1272 cents/kWh	Proposed Total Fuel Rate (including renewables and EMF) cents/kWh
		A	B	C	D	E	F	G
		Workpaper 8	Workpaper 12	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = H
1	Residential	16,637,596	$ 2,075,916,528	$ 163,876,067	7.9%	0.985	2.371	3.356
2	Small General Service	1,797,603	257,917,886	20,360,437	7.9%	1.133	2.297	3.430
3	Medium General Service	10,360,942	907,180,740	71,614,253	7.9%	0.691	2.404	3.095
4	Large General Service	9,189,937	536,849,788	42,379,754	7.9%	0.461	2.527	2.988
5	Lighting	379,481	95,551,608	7,542,992	7.9%	1.988	2.018	4.006
6	NC Retail	38,365,559	$ 3,873,416,550	$ 305,773,503				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 10	$ 1,618,076,893
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	69,946,676
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,548,130,217
10	NC Retail Allocation % - sales at generation	Workpaper 11	62.74%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 971,296,898
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	43,045,531
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,014,342,429
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 1,014,342,429
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,365,559
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.644
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.557
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 15-17	3.201
	Total Current Composite Fuel Rate - Docket E-2 Sub 1272:		
21	Current composite Fuel Rate cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17	2.106
22	Current composite EMF Rate cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18	0.298
23	Current composite EMF Interest cents/kWh	2021 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.404
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	0.797
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,365,559
27	Increase/(Decrease) in Fuel Costs	Line 25* Line 26 * 10	$ 305,773,503

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Proposed Composite Experience Modification Factor
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Reported Adjustments (e)	Reported Adjusted (Over)/Under Recovery (f)
1	April 2021 (Sub 1250) Note [1]	2.213	2.149	2,792,969	$ 1,806,864	-	$ 1,806,864
2	May Note [2]	2.996	2.151	2,587,598	21,857,325	-	21,857,325
3	June Note [3]	2.637	2.148	2,973,987	14,562,419	$ (145,865)	14,416,554
4	July	2.767	2.148	3,640,179	22,532,613	-	22,532,613
5	August	2.819	2.146	3,632,758	24,450,052	-	24,450,052
6	September	2.118	2.148	3,666,084	(1,089,005)	-	(1,089,005)
7	October	2.405	2.153	2,900,680	7,319,766	-	7,319,766
8	November	3.745	2.125	1,777,446	28,786,209	-	28,786,209
9	December (New Rates - Sub 1272)	3.213	2.140	2,791,497	29,970,992	-	29,970,992
10	January 2022	4.158	2.136	3,292,881	66,583,193	-	66,583,193
11	February Note [4]	2.478	2.112	4,045,880	14,803,795	(551)	14,803,244
12	March	2.520	2.110	3,137,475	12,855,906	-	12,855,906
13	Total Test Period Notes [1] & [2]			37,239,435	$ 244,440,129	$ (146,416)	$ 244,293,713
14	Booked 12-month (Over) / Under Recovery						$ 244,293,713
15	Adjustment to exclude Under Recovery - April - June 2021 Note [5]						(38,080,743)
16	Total 9-month (Over) / Under Recovery						$ 206,212,970
17	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(1,427,778)
18	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						5,613,062
19	Total Adjusted (Over) / Under Recovery Request						$ 210,398,254
20	Normalized Test Period MWh Sales	Exhibit 4					37,740,216
21	Experience Modification Increment / (Decrement) cents/KWh						0.557

Notes:
Totals may not foot due to rounding.
[1] April 2021 sales do not reflect 1,194 LGS MWh sales.
[2] May 2021 sales do not reflect 1,036 LGS MWh sales.
[3] Reported $ adjustment in June 2021 corrects EMF for under-reported June 2020 - May 2021 LGS sales.
[4] Reported $ adjustment in February 2022 corrects marginal fuel cost and benefit allocations to NC Retail associated with solar net metered generation.
[5] April - June 2021 were remitted in fuel Docket E-2, Sub 1272 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Reported Adjustments (e)	Reported Adjusted (Over)/Under Recovery (f)
1	April 2021 (Sub 1250)	2.275	2.080	1,133,167	$ 2,212,855		$ 2,212,855
2	May	3.282	2.080	985,317	11,844,369		11,844,369
3	June Note [3]	2.623	2.080	1,243,074	6,749,069	$ 47,988	6,797,057
4	July	2.723	2.080	1,554,529	10,000,067		10,000,067
5	August	2.678	2.080	1,595,891	9,543,510		9,543,510
6	September	2.080	2.080	1,566,329	(4,679)		(4,679)
7	October	2.677	2.080	1,090,092	6,509,020		6,509,020
8	November	2.675	2.080	1,024,290	6,089,826		6,089,826
9	December (New Rates - Sub 1272)	2.698	2.101	1,448,892	8,661,593		8,661,593
10	January 2022	3.740	2.126	1,592,256	25,697,148		25,697,148
11	February Note [4]	2.510	2.126	1,740,521	6,683,771	(227)	6,683,544
12	March	2.679	2.126	1,287,593	7,125,238		7,125,238
13	Total Test Period			16,261,952	$ 101,111,788	$ 47,761	$ 101,159,549
14	Booked 12-month (Over) / Under Recovery						$ 101,159,549
15	Adjustment to exclude Under Recovery - April - June 2021 Note [5]						(20,854,281)
16	Total 9-month (Over) / Under Recovery						$ 80,305,267
17	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(614,224)
18	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						2,414,716
19	Total Adjusted (Over) / Under Recovery Request						$ 82,105,760
20	Normalized Test Period MWh Sales	Exhibit 4					16,792,596
21	Experience Modification Increment (Decrement) cents/KWh						0.489

Notes:
Totals may not foot due to rounding.
[1] N/A
[2] N/A
[3] Reported $ adjustment in June 2021 corrects EMF for under-reported June 2020 - May 2021 LGS sales.
[4] Reported $ adjustment in February 2022 corrects marginal fuel cost and benefit allocations to NC Retail associated with solar net metered generation.
[5] April - June 2021 were remitted in fuel Docket E-2, Sub 1272 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Small General Service
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Reported Adjustments (e)	Reported Adjusted (Over)/Under Recovery (f)
1	April 2021 (Sub 1250)	2.095	2.126	137,824	$ (43,406)		$ (43,406)
2	May	2.839	2.126	127,536	909,564		909,564
3	June Note [3]	2.389	2.126	152,627	401,726	$ 5,493	407,219
4	July	2.585	2.126	183,849	843,731		843,731
5	August	2.536	2.126	188,716	774,014		774,014
6	September	1.895	2.126	192,880	(446,259)		(446,259)
7	October	2.201	2.126	148,567	112,079		112,079
8	November	2.413	2.126	126,539	363,381		363,381
9	December (New Rates - Sub 1272)	2.568	2.120	162,788	728,703		728,703
10	January 2022	4.006	2.111	158,618	3,006,746		3,006,746
11	February Note [4]	2.829	2.110	165,103	1,186,181	(26)	1,186,155
12	March	2.458	2.111	150,228	521,027		521,027
13	Total Test Period			1,895,276	$ 8,357,485	$ 5,467	$ 8,362,952
14	Booked 12-month (Over) / Under Recovery						$ 8,362,952
15	Adjustment to exclude Under Recovery - April - June 2021 Note [5]						(1,273,376)
16	Total 9-month (Over) / Under Recovery						$ 7,089,576
17	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(58,264)
18	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						229,056
19	Total Adjusted (Over) / Under Recovery Request						$ 7,260,368
20	Normalized Test Period MWh Sales	Exhibit 4					1,956,415
21	Experience Modification Increment (Decrement) cents/KWh						0.371

Notes:
Totals may not foot due to rounding.
[1] N/A
[2] N/A
[3] Reported $ adjustment in June 2021 corrects EMF for under-reported June 2020 - May 2021 LGS sales.
[4] Reported $ adjustment in February 2022 corrects marginal fuel cost and benefit allocations to NC Retail associated with solar net metered generation.
[5] April - June 2021 were remitted in fuel Docket E-2, Sub 1272 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Medium General Service
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Reported Adjustments (e)	Reported Adjusted (Over)/Under Recovery (f)
1	April 2021 (Sub 1250)	2.125	2.228	822,997	$ (849,442)		$ (849,442)
2	May	2.782	2.228	788,212	4,369,225		4,369,225
3	June Note [3]	2.490	2.228	890,739	2,333,200	$ 32,806	2,366,006
4	July	2.774	2.228	1,027,752	5,613,630		5,613,630
5	August	2.799	2.228	1,034,942	5,912,321		5,912,321
6	September	2.045	2.228	1,074,563	(1,962,880)		(1,962,880)
7	October	2.204	2.228	895,855	(217,832)		(217,832)
8	November	3.981	2.228	472,283	8,278,260		8,278,260
9	December (New Rates - Sub 1272)	3.041	2.213	817,598	6,766,628		6,766,628
10	January 2022	6.037	2.177	628,178	24,248,779		24,248,779
11	February Note [4]	2.673	2.175	1,039,371	5,179,931	(158)	5,179,773
12	March	2.350	2.170	932,757	1,673,661		1,673,661
13	Total Test Period			10,425,247	$ 61,345,481	$ 32,648	$ 61,378,129
14	Booked 12-month (Over) / Under Recovery						$ 61,378,129
15	Adjustment to exclude Under Recovery - April - June 2021 Note [5]						(5,885,789)
16	Total 9-month (Over) / Under Recovery						$ 55,492,340
17	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(366,791)
18	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						1,441,974
19	Total Adjusted (Over) / Under Recovery Request						$ 56,567,523
20	Normalized Test Period MWh Sales	Exhibit 4					10,468,785
21	Experience Modification Increment (Decrement) cents/KWh						0.540

Notes:
Totals may not foot due to rounding.
[1] N/A
[2] N/A
[3] Reported $ adjustment in June 2021 corrects EMF for under-reported June 2020 - May 2021 LGS sales.
[4] Reported $ adjustment in February 2022 corrects marginal fuel cost and benefit allocations to NC Retail associated with solar net metered generation.
[5] April - June 2021 were remitted in fuel Docket E-2, Sub 1272 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Large General Service
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Reported Adjustments (e)	Reported Adjusted (Over)/Under Recovery (f)
1	April 2021 (Sub 1250) Note [1]	2.276	2.204	670,687	$ 483,814		$ 483,814
2	May Note [2]	2.907	2.204	658,316	4,629,597		4,629,597
3	June Note [3]	2.956	2.204	659,328	4,959,116	$ (233,121)	4,725,996
4	July	2.895	2.204	845,850	5,847,655		5,847,655
5	August	3.218	2.204	785,042	7,956,895		7,956,895
6	September	2.357	2.204	804,148	1,233,559		1,233,559
7	October	2.322	2.204	737,900	868,796		868,796
8	November	12.388	2.204	136,026	13,853,225		13,853,225
9	December (New Rates - Sub 1272)	6.232	2.195	334,358	13,495,940		13,495,940
10	January 2022	3.574	2.140	894,393	12,827,379		12,827,379
11	February Note [4]	2.169	2.039	1,073,732	1,394,510	(138)	1,394,372
12	March	2.482	2.022	737,741	3,390,298		3,390,298
13	Total Test Period Notes [1] & [2]			8,337,521	$ 70,940,785	$ (233,259)	$ 70,707,527
14	Booked 12-month (Over) / Under Recovery						$ 70,707,527
15	Adjustment to exclude Under Recovery - April - June 2021 Note [5]						(9,839,407)
16	Total 9-month (Over) / Under Recovery						$ 60,868,120
17	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(378,917)
18	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						1,489,645
19	Total Adjusted (Over) / Under Recovery Request						$ 61,978,848
20	Normalized Test Period MWh Sales	Exhibit 4					8,202,098
21	Experience Modification Increment (Decrement) cents/KWh						0.756

Notes:

Totals may not foot due to rounding.

[1] April 2021 sales do not reflect 1,194 LGS MWh sales.

[2] May 2021 sales do not reflect 1,036 LGS MWh sales.

[3] Reported $ adjustment in June 2021 corrects EMF for under-reported June 2020 - May 2021 LGS sales.

[4] Reported $ adjustment in February 2022 corrects marginal fuel cost and benefit allocations to NC Retail associated with solar net metered generation.

[5] April - June 2021 were remitted in fuel Docket E-2, Sub 1272 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Lighting
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Line No.	Month		Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Reported Adjustments (e)	Reported Adjusted (Over)/Under Recovery (f)
1	April 2021 (Sub 1250)		1.403	1.392	28,294	$ 3,043		$ 3,043
2	May		1.763	1.392	28,216	104,570		104,570
3	June Note [3]		1.815	1.392	28,218	119,307	$ 969	120,276
4	July		2.199	1.392	28,198	227,530		227,530
5	August		2.327	1.392	28,167	263,312		263,312
6	September		1.716	1.392	28,164	91,254		91,254
7	October		1.561	1.392	28,266	47,703		47,703
8	November		2.493	1.392	18,309	201,517		201,517
9	December (New Rates - Sub 1272)		2.605	1.463	27,861	318,128		318,128
10	January 2022		5.787	1.655	19,436	803,141		803,141
11	February Note [4]		2.989	1.665	27,153	359,402	(2)	359,400
12	March		2.174	1.675	29,156	145,681		145,681
13	Total Test Period				319,438	$ 2,684,587	$ 967	$ 2,685,554
14	Booked 12-month (Over) / Under Recovery							$ 2,685,554
15	Adjustment to exclude Under Recovery - April - June 2021 Note [5]							(227,888)
16	Total 9-month (Over) / Under Recovery							$ 2,457,666
17	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order							(9,582)
18	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order							37,671
19	Total Adjusted (Over) / Under Recovery Request							$ 2,485,754
20	Normalized Test Period MWh Sales	Exhibit 4						320,322
21	Experience Modification Increment (Decrement) cents/KWh							0.776

Notes:
Totals may not foot due to rounding.
[1] N/A
[2] N/A
[3] Reported $ adjustment in June 2021 corrects EMF for under-reported June 2020 - May 2021 LGS sales.
[4] Reported $ adjustment in February 2022 corrects marginal fuel cost and benefit allocations to NC Retail associated with solar net metered generation.
[5] April - June 2021 were remitted in fuel Docket E-2, Sub 1272 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Normalized Test Period MWh Sales, Fuel and Fuel-Related Revenue, Fuel and Fuel-Related Expense, and System Peak
Twelve Months Ended March 31, 2022
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Exhibit 4

Line No.	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina Small General Service	North Carolina Medium General Service	North Carolina Large General Service	North Carolina Lighting
1	Test Period MWh Sales	Workpaper 9	60,559,875	37,241,666	16,261,952	1,895,276	10,425,247	8,339,752	319,438
2	Weather MWh Adjustment	Workpaper 9	719,290	442,818	389,695	36,179	152,223	(135,279)	0
3	Customer Growth MWh Adjustment	Workpaper 9	266,531	55,732	140,949	24,960	(108,685)	(2,374)	883
4	Total Normalized Test Period MWh Sales	Sum Lines 1-3	61,545,696	37,740,216	16,792,596	1,956,415	10,468,785	8,202,098	320,322
5	Test Period Fuel and Fuel-Related Revenue *		$ 1,295,094,453	$ 796,346,874					
6	Test Period Fuel and Fuel-Related Expense *		$ 1,706,863,161	$ 1,040,640,585					
7	Test Period Unadjusted (Over)/Under Recovery	Line 5 - Line 6	$ 411,768,708	$ 244,293,713					

Line No.	Description	2021 Summer Coincidental Peak (CP) KW
8	Total System Peak	12,438,953
9	NC Retail	7,737,369
10	NC Residential Peak	4,079,577
11	NC Small General Service	463,227
12	NC Medium General Service	1,974,406
13	NC Large General Service	1,220,159

Notes:
* Total Company Fuel and Fuel-Related Revenue and Fuel and Fuel-Related Expense are quantifed based on NC Retail's known share of revenues and expenses grossed up to also include the percentage of sales not belonging to NC Retail.

Rounding differences may occur.

Duke Energy Progress, LLC **Harrington Exhibit 5**
North Carolina Annual Fuel and Fuel-Related Expense
Nuclear Capacity Ratings - MWs
Twelve Months Ended March 31, 2022
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Unit	Rate Case Docket E-2, Sub 1219	Fuel Docket E-2, Sub 1272	Proposed Capacity Rating MW
Brunswick 1	938	938	938
Brunswick 2	932	932	932
Harris 1	964	964	964
Robinson 2	741	759	759
Total Company	3,575	3,593	3,593

March 2022
Monthly Fuel Filing and Baseload Report Cover Sheet

Schedule 1

DUKE ENERGY PROGRESS
SUMMARY OF MONTHLY FUEL REPORT

Line No.	Fuel Expenses:	Docket No. E-2, Sub 1286 March 2022	12 Months Ended March 2022
1	Total Fuel and Fuel-Related Costs	$ 123,420,627	$ 1,705,064,810
	MWH sales:		
2	Total System Sales	5,509,533	67,158,845
3	Less intersystem sales	594,318	6,598,971
4	Total sales less intersystem sales	4,915,215	60,559,874
5	Total fuel and fuel-related costs (¢/KWH) (Line 1/Line 4)	2.511	2.816
6	Current fuel & fuel-related cost component (¢/KWH) (per Schedule 4, Line 5a Total)	2.115	
	Generation Mix (MWH):		
	Fossil (By Primary Fuel Type):		
7	Coal	200,277	6,371,743
8	Oil	5,857	116,152
9	Natural Gas - Combustion Turbine	154,337	1,955,831
10	Natural Gas - Combined Cycle	1,972,205	21,250,607
11	Biogas	1,175	11,437
12	Total Fossil	2,333,851	29,705,770
13	Nuclear	2,104,848	29,581,602
14	Hydro - Conventional	91,290	623,493
15	Solar Distributed Generation	22,394	257,024
16	Total MWH generation	4,552,383	60,167,889

Notes:
Detail amounts may not add to totals shown due to rounding.

Schedule 2

DUKE ENERGY PROGRESS
DETAILS OF FUEL AND FUEL-RELATED COSTS

Docket No. E-2, Sub 1286

Description	March 2022	12 Months Ended March 2022
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0501110 coal consumed - steam	$ 8,144,745	$ 223,802,427
0501310 fuel oil consumed - steam	949,452	6,599,859
Total Steam Generation - Account 501	9,094,197	230,402,286
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	12,197,443	174,975,833
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	10,470,222	110,115,364
0547000 natural gas consumed - Combined Cycle	78,353,868	838,587,862
0547106 biogas consumed - Combined Cycle	57,886	530,068
0547200 fuel oil consumed	676,800	14,785,734
Total Other Generation - Account 547	89,558,776	964,019,028
Reagents		
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	479,831	15,495,579
Total Reagents	479,831	15,495,579
By-products		
Net proceeds from sale of by-products	(394,343)	11,791,627
Total By-products	(394,343)	11,791,627
Total Fossil and Nuclear Fuel Expenses		
Included in Base Fuel Component	110,935,904	1,396,684,353
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (PURPA)	2,792,318	50,453,135
Capacity component of purchased power (renewables)	2,185,764	32,794,146
Fuel and fuel-related component of purchased power	33,910,648	485,750,102
Total Purchased Power and Net Interchange - Account 555	38,888,730	568,997,383
Less:		
Fuel and fuel-related costs recovered through intersystem sales	26,403,992	260,558,003
Solar Integration Charge	15	193
Miscellaneous Fees Collected	-	58,730
Total Fuel Credits - Accounts 447/456	26,404,007	260,616,926
Total Fuel and Fuel-Related Costs	$ 123,420,627	$ 1,705,064,810

NOTE: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY PROGRESS
PURCHASED POWER AND INTERCHANGE
SYSTEM REPORT - NORTH CAROLINA VIEW

MARCH 2022

Schedule 3, Purchases
Page 1 of 4

Purchased Power	Total	Capacity	Non-capacity			
Economic Purchases	**$**	**$**	**mWh**	**Fuel $**	**Fuel-related $**	**Not Fuel $ Not Fuel-related $**
Broad River Energy, LLC	$ 8,803,338	$ 7,109,063	25,692	$ 1,371,575	$ 322,700	-
City of Fayetteville	875,730	715,000	1,310	160,730	-	-
DE Carolinas - Native Load Transfer	1,940,790	-	42,635	1,557,183	376,473	$ 7,134
DE Carolinas - Native Load Transfer Benefit	306,172	-	-	306,172	-	-
DE Carolinas - Fees	(11,777)	-	-	-	(11,777)	-
Haywood EMC	27,750	27,750	-	-	-	-
NCEMC	3,585,394	2,942,462	10,186	599,779	43,153	-
PJM Interconnection, LLC	(600)	-	-	-	(600)	-
Southern Company Services	7,549,166	2,042,083	104,476	5,085,909	421,174	-
	$ 23,075,963	**$ 12,836,358**	**184,299**	**$ 9,081,348**	**$ 1,151,123**	**$ 7,134**
Renewable Energy Purchases						
REPS	$ 11,100,804	-	179,094	-	$ 11,100,804	-
DERP Qualifying Facilities	109,518	-	2,187	-	107,422	$ 2,096
DERP Net Metering Excess Generation	-	-	-	-	-	-
	$ 11,210,322	**-**	**181,281**	**-**	**$ 11,208,226**	**$ 2,096**
HB589 PURPA Purchases						
Other Qualifying Facilities	$ 17,427,391	-	318,194	-	$ 17,427,391	-
CPRE - Purchased Power	585,427	-	12,730	-	-	$ 585,427
	$ 18,012,818	**-**	**330,924**	**-**	**$ 17,427,391**	**585,427**
Non-dispatchable Purchases						
DE Carolinas - Emergency	-	-	-	-	-	-
DE Carolinas - Reliability	-	-	-	-	-	-
Dominion Energy South Carolina - Emergency	-	-	-	-	-	-
Virginia Electric and Power Company - Emergency	-	-	-	-	-	-
Energy Imbalance	$ 22,356	-	437	$ 20,642	-	$ 1,714
Generation Imbalance	-	-	2	-	-	-
	$ 22,356	**-**	**439**	**$ 20,642**	**-**	**$ 1,714**
Total Purchased Power	**$ 52,321,459**	**$ 12,836,358**	**696,943**	**$ 9,101,990**	**$ 29,786,740**	**$ 596,371**

NOTE: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY PROGRESS
INTERSYSTEM SALES*
SYSTEM REPORT - NORTH CAROLINA VIEW

MARCH 2022

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
DE Carolinas - As Available Capacity	$ 17,471	$ 17,471	-	-	-
DE Carolinas - Emergency	-	-	-	-	-
South Carolina Public Service Authority - Emergency	-	-	-	-	-
Market Based:					
NCEMC Purchase Power Agreement	1,162,913	652,500	9,141	$ 535,070	$ (24,657)
PJM Interconnection, LLC	63,885	-	1,600	54,282	9,603
Other:					
DE Carolinas - Native Load Transfer	22,219,925	-	583,547	21,534,532	685,393
DE Carolinas - Native Load Transfer Benefit	4,278,787	-	-	4,278,787	-
Generation Imbalance	1,431	-	30	1,321	110
Total Intersystem Sales	**$ 27,744,412**	**$ 669,971**	**594,318**	**$ 26,403,992**	**$ 670,449**

* Sales for resale other than native load priority.
NOTE: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY PROGRESS
PURCHASED POWER AND INTERCHANGE
SYSTEM REPORT - NORTH CAROLINA VIEW

Twelve Months Ended
MARCH 2022

Purchased Power	**Total**	**Capacity**	**Non-capacity**			
						Not Fuel $
Economic Purchases	**$**	**$**	**mWh**	**Fuel $**	**Fuel-related $**	**Not Fuel-related $**
Broad River Energy, LLC	$ 69,699,983	$ 46,060,240	379,574	$ 18,160,804	$ 5,478,939	-
City of Fayetteville	13,597,049	12,798,500	7,048	679,666	118,883	-
DE Carolinas - Native Load Transfer	44,679,615	-	955,476	36,912,150	7,684,684	$ 82,781
DE Carolinas - Native Load Transfer Benefit	7,719,479	-	-	7,719,479	-	-
DE Carolinas - Fees	(15,711)	-	-	-	(15,711)	-
Haywood EMC	335,250	335,250	-	-	-	-
NCEMC	56,489,730	38,823,915	244,117	16,793,816	871,999	-
PJM Interconnection, LLC	890,637	-	9,613	464,638	425,999	-
Southern Company Services	128,751,117	30,343,278	2,125,825	88,808,630	9,599,209	-
	$ 322,147,149	**$ 128,361,183**	**3,721,653**	**$ 169,539,183**	**$ 24,164,002**	**$ 82,781**
Renewable Energy Purchases						
REPS	$ 148,264,899	-	2,283,784	-	$ 148,264,899	-
DERP Qualifying Facilities	1,393,167	-	33,530	-	1,327,729	$ 65,438
DERP Net Metering Excess Generation	7,068	$ 1,725	210	-	-	5,343
	$ 149,665,134	**$ 1,725**	**2,317,524**	**-**	**$ 149,592,628**	**$ 70,781**
HB589 PURPA Purchases						
Other Qualifying Facilities	$ 224,676,059	-	3,801,826	-	$ 224,676,059	-
CPRE - Purchased Power	4,550,705	-	113,287	-	-	$ 4,550,705
	$ 229,226,764	**-**	**3,915,113**	**-**	**$ 224,676,059**	**4,550,705**
Non-dispatchable Purchases						
DE Carolinas - Emergency	-	-	-	-	-	-
DE Carolinas - Reliability	$ 1,190,669	$ 14,000	21,826	$ 717,768	-	$ 458,901
Dominion Energy South Carolina - Emergency	-	-	-	-	-	-
Virginia Electric and Power Company - Emergency	-	-	-	-	-	-
Energy Imbalance	275,697	-	6,712	264,220	-	11,477
Generation Imbalance	59,249	-	2,346	43,521	-	15,728
	$ 1,525,615	**14,000**	**30,884**	**$ 1,025,509**	**-**	**$ 486,106**
Total Purchased Power	**$ 702,564,662**	**$ 128,376,908**	**9,985,174**	**$ 170,564,692**	**$ 398,432,689**	**$ 5,190,373**

NOTE: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY PROGRESS
INTERSYSTEM SALES*
SYSTEM REPORT - NORTH CAROLINA VIEW

Twelve Months Ended
MARCH 2022

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
DE Carolinas - As Available Capacity	$ 320,001	$ 320,001	-	-	-
DE Carolinas - Emergency	-	-	-	-	-
South Carolina Public Service Authority - Emergency	1,235	-	16	$ 911	$ 324
Market Based:					
NCEMC Purchase Power Agreement	14,985,025	7,830,000	147,226	7,527,400	(372,375)
PJM Interconnection, LLC	1,601,203	-	42,648	1,455,099	146,104
Other:					
DE Carolinas - Native Load Transfer	230,700,039	-	6,408,617	221,135,548	9,564,491
DE Carolinas - Native Load Transfer Benefit	30,429,147	-	-	30,429,147	-
Generation Imbalance	10,590	-	464	9,898	692
Total Intersystem Sales	**$ 278,047,240**	**$ 8,150,001**	**6,598,971**	**$ 260,558,003**	**$ 9,339,236**

* Sales for resale other than native load priority.
NOTE: Detail amounts may not add to totals shown due to rounding.

Schedule 4

DUKE ENERGY PROGRESS
(OVER) / UNDER RECOVERY OF FUEL COSTS
MARCH 2022

Line No.			Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total
1	1a. System Retail kWh sales	Input						4,915,215,160
	1b. System kWh Sales at generation	Input						5,071,635,861
2	2a. DERP Net Metered kWh generation	Input						2,890,724
	2b. Line loss percentage from Cost of Service	Input Annually						3.546%
	2c. DERP Net Metered kWh at generation	L2a * (1 + 2b)						2,993,229
3	Adjusted System kWh sales	L1b + L2c						5,074,629,090
4	4a. N.C. Retail kWh sales	Input	1,287,593,026	150,227,857	932,757,242	737,740,764	29,156,238	3,137,475,127
	4b. Line loss percentage from Cost of Service	Input Annually	4.081%	4.080%	3.929%	2.901%	4.078%	
	4c. NC kWh Sales at generation	4a * (1+4b)	1,340,139,697	156,357,154	969,405,274	759,142,624	30,345,230	3,255,389,979
	4d. NC allocation % by customer class	Calculated	41.167%	4.803%	29.778%	23.320%	0.932%	
	4e. NC retail % of actual system total	L4c NC Total / L1b Total System						64.188%
	4f. NC retail % of adjusted system total	L4c NC Total / L3 Total System						64.150%
5	Approved fuel and fuel-related rates (¢/kWh)							
	5a Billed rates by class (¢/kWh)	Input Annually	2.126	2.111	2.170	2.022	1.675	2.110
	5b Billed fuel expense	L4a * L5a / 100	$27,373,942	$3,171,352	$20,244,795	$14,918,357	$488,231	$66,196,678
6	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)							
	6a NC Docket E-2, Sub 1272 allocation factor	Input Annually	43.398%	4.623%	27.681%	23.465%	0.834%	100.000%
	6b System incurred expense	Input						$118,507,709
	6c NC incurred expense by class	L4f * L6a * L6b	$32,992,087	$3,514,504	$21,043,677	$17,838,516	$633,912	$76,022,696
	6d NC Incurred base fuel rates (¢/kWh)	L6c / L4a * 100	2.56231	2.33945	2.25607	2.41799	2.17419	2.42305
7	Incurred renewable purchased power capacity rates (¢/kWh)							
	7a NC retail production plant %	Input Annually						60.865%
	7b Production plant allocation factors	Input Annually	49.741%	5.871%	28.872%	15.517%	0.000%	100.000%
	7c System incurred expense	Input						4,978,081.18
	7d NC incurred renewable capacity expense	L7a* L7b* L7c	$1,507,093	$177,875	$874,779	$470,140	$0	$3,029,887
	7e NC incurred rates by class	L7d / L4a * 100	0.11705	0.11840	0.09378	0.06373	-	0.09657
8	Total incurred rates by class (¢/kWh)	L6h + 7e	2.6794	2.4579	2.3499	2.4817	2.1742	
9	Difference in ¢/kWh (incurred - billed)	L8 - L5a	0.55338	0.34682	0.17943	0.45955	0.49966	
10	(Over) / under recovery [See footnote]	L9 * L4a / 100	**$7,125,238**	**$521,027**	**$1,673,661**	**$3,390,298**	**$145,681**	**$12,855,905**
11	Adjustments	Input						
12	Total (over) / under recovery [See footnote]	L10 + L11	**$7,125,238**	**$521,027**	**$1,673,661**	**$3,390,298**	**$145,681**	**$12,855,905**
13	Total System Incurred Expenses							$123,485,791
14	Less: Jurisdictional allocation adjustment	Input						65,163
15	Total Fuel and Fuel-related Costs per Schedule 2							$123,420,628
16	(Over) / under recovery for each month of the current test period [See footnote]							

			(Over) / Under Recovery					
		Total To Date	Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total Company
	April 2021	$1,806,864	2,212,855	(43,406)	(849,442)	483,814	3,043	$1,806,864
	May 2021	$23,664,189	11,844,369	909,564	4,369,225	4,629,597	104,570	$21,857,325
_/1	June 2021	$38,080,743	6,797,057	407,219	2,366,006	4,725,996	120,276	$14,416,554
	July 2021	$60,613,356	10,000,067	843,731	5,613,630	5,847,655	227,530	$22,532,613
	August 2021	$85,063,408	9,543,510	774,014	5,912,321	7,956,895	263,312	$24,450,052
	September 2021	$83,974,403	(4,679)	(446,259)	(1,962,880)	1,233,559	91,254	($1,089,005)
	October 2021	$91,294,169	6,509,020	112,079	(217,832)	868,796	47,703	$7,319,766
	November 2021	$120,080,378	6,089,826	363,381	8,278,260	13,853,225	201,517	$28,786,209
	December 2021	$150,051,370	8,661,593	728,703	6,766,628	13,495,940	318,128	$29,970,992
	January 2022	$216,634,563	25,697,148	3,006,746	24,248,779	12,827,379	803,141	$66,583,193
	February 2022	$231,437,807	6,683,544	1,186,155	5,179,773	1,394,372	359,400	$14,803,244
	March 2022	$244,293,712	7,125,238	521,027	1,673,661	3,390,298	145,681	$12,855,905
	Total		**$101,159,548**	**$8,362,954**	**$61,378,129**	**$70,707,526**	**$2,685,555**	**$244,293,712**

Notes:

Detail amounts may not recalculate due to percentages presented as rounded.

Presentation of (over)/under collected amounts reflects a regulatory asset or liability. Over collections, or regulatory liabilities, are shown as negative amounts. Under collections, or regulatory assets, are shown as positive amounts.

_/1 Includes prior period adjustments.

Duke Energy Progress
Fuel and Fuel Related Cost Report
MARCH 2022

Description	Mayo Steam	Roxboro Steam	Asheville CC/CT	Smith Energy Complex CC/CT	Sutton CC/CT	Lee CC	Blewett CT
Cost of Fuel Purchased ($)							
Coal	$ 4,634,736	$ 18,667,406	-	-	-	-	-
Oil	467,385	713,670	$ 5,230,246	-	-	-	-
Gas - CC	-	-	13,743,138	$ 23,969,326	$ 17,155,851	$ 23,485,553	-
Gas - CT	-	-	1,095,669	8,743,916	249,917	-	-
Biogas	-	-	-	374,784	-	-	-
Total	$ 5,102,121	$ 19,381,076	$ 20,069,053	$ 33,088,026	$ 17,405,768	$ 23,485,553	-
Average Cost of Fuel Purchased (¢/MBTU)							
Coal	298.12	322.97	-	-	-	-	-
Oil	2,376.49	2,375.73	2,700.14	-	-	-	-
Gas - CC	-	-	602.77	506.37	614.29	557.01	-
Gas - CT	-	-	642.96	537.17	1,131.72	-	-
Biogas	-	-	-	4,176.33	-	-	-
Weighted Average	324.08	333.59	605.56	519.41	618.35	557.01	-
Cost of Fuel Burned ($)							
Coal	$ 3,247,348	$ 4,897,397	-	-	-	-	-
Oil - CC	-	-	-	$ 37,549	-	-	-
Oil - Steam/CT	362,600	586,852	$ 509,104	44,616	$ 2,241	-	$ 3,968
Gas - CC	-	-	13,743,138	23,969,326	17,155,851	$ 23,485,553	-
Gas - CT	-	-	1,095,669	8,743,916	249,917	-	-
Biogas	-	-	-	374,784	-	-	-
Nuclear	-	-	-	-	-	-	-
Total	$ 3,609,948	$ 5,484,249	$ 15,347,911	$ 33,170,191	$ 17,408,009	$ 23,485,553	$ 3,968
Average Cost of Fuel Burned (¢/MBTU)							
Coal	278.65	325.35	-	-	-	-	-
Oil - CC	-	-	-	1,682.30	-	-	-
Oil - Steam/CT	1,947.47	2,017.30	2,095.60	1,682.35	2,000.89	-	1,688.51
Gas - CC	-	-	602.77	506.37	614.29	557.01	-
Gas - CT	-	-	642.96	537.17	1,131.72	-	-
Biogas	-	-	-	4,176.33	-	-	-
Nuclear	-	-	-	-	-	-	-
Weighted Average	304.89	357.43	620.19	520.30	618.41	557.01	1,688.51
Average Cost of Generation (¢/kWh)							
Coal	4.17	4.00	-	-	-	-	-
Oil - CC	-	-	-	18.69	-	-	-
Oil - Steam/CT	29.17	24.18	35.00	18.06	20.08	-	-
Gas - CC	-	-	3.99	3.45	4.45	4.30	-
Gas - CT	-	-	10.70	6.42	11.32	-	-
Biogas	-	-	-	31.89	-	-	-
Nuclear	-	-	-	-	-	-	-
Weighted Average	4.57	4.39	4.31	3.98	4.49	4.30	-
Burned MBTU's							
Coal	1,165,381	1,505,251	-	-	-	-	-
Oil - CC	-	-	-	2,232	-	-	-
Oil - Steam/CT	18,619	29,091	24,294	2,652	112	-	235
Gas - CC	-	-	2,279,998	4,733,601	2,792,781	4,216,373	-
Gas - CT	-	-	170,410	1,627,767	22,083	-	-
Biogas	-	-	-	8,974	-	-	-
Nuclear	-	-	-	-	-	-	-
Total	1,184,000	1,534,342	2,474,702	6,375,226	2,814,976	4,216,373	235
Net Generation (mWh)							
Coal	77,813	122,464	-	-	-	-	-
Oil - CC	-	-	-	201	-	-	-
Oil - Steam/CT	1,243	2,427	1,454	247	11	-	(53)
Gas - CC	-	-	344,062	695,683	385,763	546,697	-
Gas - CT	-	-	10,241	136,205	2,208	-	-
Biogas	-	-	-	1,175	-	-	-
Nuclear	-	-	-	-	-	-	-
Hydro (Total System)							
Solar (Total System)							
Total	79,056	124,891	355,757	833,511	387,982	546,697	(53)
Cost of Reagents Consumed ($)							
Ammonia	-	-	-	$ 65,209	-	-	-
Limestone	$ 115,070	$ 101,245	-	-	-	-	-
Re-emission Chemical	-	-	-	-	-	-	-
Sorbents	151,770	46,537	-	-	-	-	-
Urea	-	-	-	-	-	-	-
Total	$ 266,840	$ 147,782	-	$ 65,209	-	-	-

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit, terminal and tolling agreement activity.
Cents/MBTU and cents/kWh are not computed when costs and/or net generation is negative.
Lee and Wayne oil burn is associated with inventory consumption shown on Schedule 6 for Wayne.
Re-emission chemical reagent expense is not recoverable in NC.
*12ME MBTUs burned for Gas-CC include an adjustment of (455,436) for February, 2022.

Duke Energy Progress
Fuel and Fuel Related Cost Report
MARCH 2022

Description	Darlington CT	Wayne County CT	Weatherspoon CT	Brunswick Nuclear	Harris Nuclear	Robinson Nuclear	Current Month	Total 12 ME MARCH 2022	
Cost of Fuel Purchased ($)									
Coal	-	-	-	-	-	-	$23,302,142	$222,882,377	
Oil	-	-	-	-	-	-	6,411,301	21,423,518	
Gas - CC	-	-	-	-	-	-	78,353,868	838,587,862	
Gas - CT	$ 65,785	$ 314,911	$ 24	-	-	-	10,470,222	110,115,364	
Biogas	-	-	-	-	-	-	374,784	2,658,512	
Total	$ 65,785	$ 314,911	$ 24	-	-	-	$118,912,317	$1,195,667,633	
Average Cost of Fuel Purchased (¢/MBTU)									
Coal	-	-	-	-	-	-	317.70	325.57	
Oil	-	-	-	-	-	-	2,633.95	1,978.90	
Gas - CC	-	-	-	-	-	-	558.76	550.56	*See note
Gas - CT	538.56	523.22	-	-	-	-	553.20	507.09	
Biogas	-	-	-	-	-	-	4,176.33	3,139.22	
Weighted Average	538.56	523.22	-	-	-	-	505.96	489.80	
Cost of Fuel Burned ($)									
Coal	-	-	-	-	-	-	$8,144,745	$223,802,427	
Oil - CC	-	-	-	-	-	-	37,549	890,837	
Oil - Steam/CT	$ 79,167	-	$ 155	-	-	-	1,588,703	20,494,758	
Gas - CC	-	-	-	-	-	-	78,353,868	838,587,862	
Gas - CT	65,785	$ 314,911	24	-	-	-	10,470,222	110,115,364	
Biogas	-	-	-	-	-	-	374,784	2,658,512	
Nuclear	-	-	-	$ 4,255,966	$ 4,506,683	$ 3,434,794	12,197,443	174,975,833	
Total	$ 144,952	$ 314,911	$ 179	$ 4,255,966	$ 4,506,683	$ 3,434,794	$111,167,314	$1,371,525,593	
Average Cost of Fuel Burned (¢/MBTU)									
Coal	-	-	-	-	-	-	304.97	311.28	
Oil - CC	-	-	-	-	-	-	1,682.30	1,660.43	
Oil - Steam/CT	1,720.27	-	1,722.22	-	-	-	1,995.51	1,632.06	
Gas - CC	-	-	-	-	-	-	558.76	550.56	*See note
Gas - CT	538.56	523.22	-	-	-	-	553.20	507.09	
Biogas	-	-	-	-	-	-	4,176.33	3,139.22	
Nuclear	-	-	-	53.11	60.30	57.90	56.94	56.89	
Weighted Average	861.94	523.22	1,988.89	53.11	60.30	57.90	277.25	247.17	
Average Cost of Generation (¢/kWh)									
Coal	-	-	-	-	-	-	4.07	3.51	
Oil - CC	-	-	-	-	-	-	18.69	8.31	
Oil - Steam/CT	24.22	-	-	-	-	-	28.09	19.44	
Gas - CC	-	-	-	-	-	-	3.97	3.95	
Gas - CT	7.78	6.41	-	-	-	-	6.78	5.63	
Biogas	-	-	-	-	-	-	31.89	23.24	
Nuclear	-	-	-	0.55	0.61	0.59	0.58	0.59	
Weighted Average	12.37	6.41	-	0.55	0.61	0.59	2.44	2.28	
Burned MBTU's									
Coal	-	-	-	-	-	-	2,670,632	71,897,063	
Oil - CC	-	-	-	-	-	-	2,232	53,651	
Oil - Steam/CT	4,602	-	9	-	-	-	79,614	1,255,757	
Gas - CC	-	-	-	-	-	-	14,022,753	152,314,336	*See note
Gas - CT	12,215	60,187	-	-	-	-	1,892,662	21,714,952	
Biogas	-	-	-	-	-	-	8,974	84,687	
Nuclear	-	-	-	8,013,721	7,474,306	5,931,777	21,419,804	307,571,316	
Total	16,817	60,187	9	8,013,721	7,474,306	5,931,777	40,096,671	554,891,762	*See note
Net Generation (mWh)									
Coal	-	-	-	-	-	-	200,277	6,371,743	
Oil - CC	-	-	-	-	-	-	201	10,715	
Oil - Steam/CT	327	-	-	-	-	-	5,656	105,437	
Gas - CC	-	-	-	-	-	-	1,972,205	21,250,607	
Gas - CT	845	4,910	(72)	-	-	-	154,337	1,955,831	
Biogas	-	-	-	-	-	-	1,175	11,437	
Nuclear	-	-	-	779,395	739,405	586,048	2,104,848	29,581,602	
Hydro (Total System)							91,290	623,493	
Solar (Total System)							22,394	257,024	
Total	1,172	4,910	(72)	779,395	739,405	586,048	4,552,383	60,167,889	
Cost of Reagents Consumed ($)									
Ammonia	-	-	-	-	-	-	$65,209	$3,001,134	
Limestone	-	-	-	-	-	-	216,315	9,518,198	
Re-emission Chemical	-	-	-	-	-	-	-	69,146	
Sorbents	-	-	-	-	-	-	198,307	2,976,247	
Urea	-	-	-	-	-	-	0	0	
Total	-	-	-	-	-	-	$479,831	$15,564,725	

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
MARCH 2022

Schedule 6
Page 1 of 2

Description	Mayo	Roxboro	Asheville	Smith Energy Complex	Sutton	Lee	Blewett
Coal Data:							
Beginning balance	209,675	716,026	-	-	-	-	-
Tons received during period	59,998	228,092	-	-	-	-	-
Inventory adjustments	-	-	-	-	-	-	-
Tons burned during period	43,707	61,710	-	-	-	-	-
Ending balance	225,966	882,408	-	-	-	-	-
MBTUs per ton burned	26.66	24.39	-	-	-	-	-
Cost of ending inventory ($/ton)	74.30	79.31	-	-	-	-	-
Oil Data:							
Beginning balance	249,431	330,356	2,782,892	7,033,731	2,423,636	-	683,353
Gallons received during period	142,515	217,683	1,403,642	-	-	-	-
Miscellaneous use and adjustments	(978)	(15,004)	0	-	-	-	-
Gallons burned during period	135,266	211,852	176,858	34,887	799	-	1,677
Ending balance	255,702	321,183	4,009,676	6,998,844	2,422,837	-	681,676
Cost of ending inventory ($/gal)	2.68	2.77	2.88	2.36	2.80	-	2.37
Natural Gas Data:							
Beginning balance	-	-	-	-	-	-	-
MCF received during period	-	-	2,374,722	6,156,129	2,723,887	4,080,637	-
MCF burned during period	-	-	2,374,722	6,156,129	2,723,887	4,080,637	-
Ending balance	-	-	-	-	-	-	-
Biogas Data:							
Beginning balance	-	-	-	-	-	-	-
MCF received during period	-	-	-	8,685	-	-	-
MCF burned during period	-	-	-	8,685	-	-	-
Ending balance	-	-	-	-	-	-	-
Limestone/Lime Data:							
Beginning balance	16,802	64,332	-	-	-	-	-
Tons received during period	6,860	8,972	-	-	-	-	-
Inventory adjustments	-	-	-	-	-	-	-
Tons consumed during period	1,496	1,809	-	-	-	-	-
Ending balance	22,166	71,495	-	-	-	-	-
Cost of ending inventory ($/ton)	77.17	55.16	-	-	-	-	-

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit, terminal and tolling agreement activity.
Gas is burned as received; therefore, inventory balances are not maintained.
The oil inventory data for Wayne reflects the common usage of the oil tank used for both Wayne and Lee units.

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
MARCH 2022

Description	Darlington	Wayne County	Weatherspoon	Brunswick	Harris	Robinson	Current Month	Total 12 ME March 2022
Coal Data:								
Beginning balance	-	-	-	-	-	-	925,701	1,095,907
Tons received during period	-	-	-	-	-	-	288,090	2,645,030
Inventory adjustments	-	-	-	-	-	-	-	227,157
Tons burned during period	-	-	-	-	-	-	105,417	2,859,721
Ending balance	-	-	-	-	-	-	1,108,374	1,108,374
MBTUs per ton burned	-	-	-	-	-	-	25.33	25.14
Cost of ending inventory ($/ton)	-	-	-	-	-	-	78.29	78.29
Oil Data:								
Beginning balance	9,567,647	8,473,136	428,471	0	180,337	0	32,152,990	35,288,750
Gallons received during period	-	-	-	-	-	-	1,763,840	7,844,878
Miscellaneous use and adjustments	-	-	-	-	-	-	(15,982)	(138,127)
Gallons burned during period	33,081	-	66	-	-	-	594,486	9,689,142
Ending balance	9,534,566	8,473,136	428,405	0	180,337	0	33,306,362	33,306,362
Cost of ending inventory ($/gal)	2.39	2.41	2.36	0.00	2.31	0.00	2.48	2.48
Natural Gas Data:								
Beginning balance	-	-	-	-	-	-	-	-
MCF received during period	11,917	58,211	-	-	-	-	15,405,503	168,307,728
MCF burned during period	11,917	58,211	-	-	-	-	15,405,503	168,307,728
Ending balance	-	-	-	-	-	-	-	-
Biogas Data:								
Beginning balance	-	-	-	-	-	-	-	-
MCF received during period	-	-	-	-	-	-	8,685	81,901
MCF burned during period	-	-	-	-	-	-	8,685	81,901
Ending balance	-	-	-	-	-	-	-	-
Limestone/Lime Data:								
Beginning balance	-	-	-	-	-	-	81,134	92,969
Tons received during period	-	-	-	-	-	-	15,832	158,214
Inventory adjustments	-	-	-	-	-	-	-	(1,117)
Tons consumed during period	-	-	-	-	-	-	3,305	156,404
Ending balance	-	-	-	-	-	-	93,661	93,661
Cost of ending inventory ($/ton)	-	-	-	-	-	-	60.37	60.37

Schedule 7

DUKE ENERGY PROGRESS

ANALYSIS OF COAL PURCHASED

MARCH 2022

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
MAYO	SPOT	-	-	-
	CONTRACT	59,998	$ 4,434,494	$ 73.91
	FIXED TRANSPORTATION/ADJUSTMENTS	-	$ 200,242	-
	TOTAL	59,998	$ 4,634,736	$ 77.25
ROXBORO	SPOT	35,831	$ 2,950,137	$ 82.33
	CONTRACT	192,261	$ 15,057,340	78.32
	FIXED TRANSPORTATION/ADJUSTMENTS	-	$ 659,928	-
	TOTAL	228,092	$ 18,667,405	$ 81.84
ALL PLANTS	SPOT	35,831	$ 2,950,137	$ 82.33
	CONTRACT	252,259	19,491,834	77.27
	FIXED TRANSPORTATION/ADJUSTMENTS	-	860,170	-
	TOTAL	288,090	$ 23,302,141	$ 80.88

Schedule 8

DUKE ENERGY PROGRESS

ANALYSIS OF COAL QUALITY RECEIVED

MARCH 2022

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
MAYO	6.69	7.82	12,956	2.25
ROXBORO	7.24	8.56	12,670	1.71

Schedule 9

DUKE ENERGY PROGRESS
ANALYSIS OF OIL PURCHASED
MARCH 2022

	ASHEVILLE CC	MAYO	ROXBORO
VENDOR	Hightowers Petroleum and Indigo	Greensboro Tank Farm	Greensboro Tank Farm
SPOT/CONTRACT	Contract	Contract	Contract
SULFUR CONTENT %	0	0	0
GALLONS RECEIVED	1,403,642	142,515	217,683
TOTAL DELIVERED COST	$ 5,230,246	$ 467,385	$ 713,670
DELIVERED COST/GALLON	$ 3.73	$ 3.28	$ 3.28
BTU/GALLON	138,000	138,000	138,000

Duke Energy Progress Power Plant Performance Data Twelve Month Summary
Report Period: April 2021 - March 2022

Unit	Net Generation (MWH)	Capacity Rating (MW)	Capacity Factor (%)	Equivalent Availability (%)
Brunswick 1	7,365,243	938	89.64	88.20
Brunswick 2	7,788,528	932	95.40	94.15
Harris 1	7,992,167	964	94.64	92.85
Robinson 2	6,435,664	759	96.79	94.61

EAF is calculated using Standard NERC calculation and excludes OMC events

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2021 through March, 2022
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Lee Energy Complex	1A	1,232,981	225	62.56	74.74
Lee Energy Complex	1B	1,320,297	227	66.40	79.81
Lee Energy Complex	1C	1,293,666	228	64.77	77.86
Lee Energy Complex	ST1	2,465,613	379	74.26	91.15
Lee Energy Complex	Block Total	6,312,557	1,059	68.05	82.37
Smith Energy Complex	7	963,844	193	57.01	70.19
Smith Energy Complex	8	1,016,606	193	60.13	71.50
Smith Energy Complex	ST4	1,130,259	184	70.12	77.00
Smith Energy Complex	9	1,221,848	215	64.87	78.52
Smith Energy Complex	10	1,262,804	215	67.05	78.55
Smith Energy Complex	ST5	1,630,077	252	73.84	87.28
Smith Energy Complex	Block Total	7,225,438	1,252	65.88	77.70
Sutton Energy Complex	1A	1,288,891	224	65.68	78.23
Sutton Energy Complex	1B	1,316,487	224	67.09	79.62
Sutton Energy Complex	ST1	1,567,398	271	66.02	89.62
Sutton Energy Complex	Block Total	4,172,776	719	66.25	82.95
Asheville CC	ACC CT5	1,081,676	190	64.94	82.82
Asheville CC	ACC CT7	1,289,252	190	77.46	82.70
Asheville CC	ACC ST6	531,356	90	67.40	77.13
Asheville CC	ACC ST8	659,704	90	83.68	91.17
Asheville CC	Block Total	3,561,988	560	72.59	83.21

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2021 through March, 2022

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Mayo 1	1,042,234	713	16.69	48.88
Roxboro 2	1,111,902	673	18.86	73.31
Roxboro 3	2,270,096	698	37.13	75.42
Roxboro 4	1,464,980	711	23.52	50.02

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2021 through March, 2022
Other Cycling Steam Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Roxboro	1	515,902	380	15.50	69.25

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2021 through March, 2022
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Asheville CT	255,449	370	88.68
Blewett CT	-166	68	88.20
Darlington CT	6,630	264	96.88
Smith Energy Complex CT	1,509,071	960	89.10
Sutton Fast Start CT	34,407	98	89.60
Wayne County	221,910	959	94.75
Weatherspoon CT	596	164	98.38

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Power Plant Performance Data

Twelve Month Summary
April, 2021 through March, 2022
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Blewett	105,765	27.0	92.81
Marshall	1,624	4.0	65.30
Tillery	149,586	85.0	96.45
Walters	366,518	113.0	62.01

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress Base Load Power Plant Performance Review Plan
Report Period: March 2022

Station	Unit	Date of Outage	Duration of Outage (Hours)	Scheduled / Unscheduled	Cause of Outage	Reason Outage Occurred	Remedial Actions Taken
Brunswick	1	03/04/2022 - 04/01/2022	647.53	Scheduled	Refueling outage B1R24	Normal scheduled refueling outage.	N/A
	2						
Harris	1						
Robinson	2						

Duke Energy Progress
Baseload Steam and CHP Units
Performance Review Plan
March 2022

DEP Asheville CC

No Outages at Baseload Units During the Month.

Lee Energy Complex

Unit	Duration of Outage	Type of	Cause of Outage		Reason Outage Occurred	Remedial Action
ST1	3/25/2022 11:40:00 PM 3/31/2022 12:00:00 AM	Sch	4011	Diaphragms	Planned GMS Steam Turbine major outage	

Mayo Station

Unit	Duration of Outage	Type of	Cause of Outage		Reason Outage Occurred	Remedial Action
1	2/22/2022 8:00:00 AM To 3/3/2022 2:00:00 PM	Sch	4240	Bearings	#6 Main Turbine bearing had high temperature when the unit was coasting down after coming off-line for RS. All indications are the bearing is wiped and we will need to inspect and repair.	

Roxboro Station

Unit	Duration of Outage	Type of	Cause of Outage		Reason Outage Occurred	Remedial Action
2	3/8/2022 8:00:00 PM To 3/10/2022 4:25:00 PM	Unsch	1000	Waterwall (Furnace wall)	External Waterwall Tube Leak	
2	3/21/2022 7:00:00 AM To 3/27/2022 2:00:00 AM	Sch	8140	Reaction tanks including agitators	Replace FGD Agitator Seals	
4	3/25/2022 7:00:00 AM To 4/2/2022 12:00:00 AM	Sch	4630	Liquid cooling system	Stator Cooling Water Conductivity High	

Smith Energy Complex

Unit	Duration of Outage	Type of	Cause of Outage		Reason Outage Occurred	Remedial Action
9	3/26/2022 12:02:00 AM 3/31/2022 12:00:00 AM	Sch	5272	Boroscope inspection	Borescope inspection. Air Separator Inspection by the OEM. BOP outage.	
10	3/26/2022 2:11:00 AM 3/31/2022 12:00:00 AM	Sch	5272	Boroscope inspection	Borescope inspection. Air Separator Inspection by the OEM.	
ST5	3/27/2022 12:22:00 AM 3/31/2022 12:00:00 AM	Sch	5272	Boroscope inspection	Borescope inspections on CT 9 & 10. Boiler inspections on HRSG's 9 & 10.	

Sutton Energy Complex

No Outages at Baseload Units During the Month.

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership

Duke Energy Progress Base Load Power Plant Performance Review Plan
Report Period: March 2022

	Brunswick 1	Brunswick 2	Harris 1	Robinson 2
(A) MDC (MW)	938	932	964	759
(B) Period Hours	743	743	743	743
(C1) Net Gen (MWH)	83,176	696,219	739,405	586,048
(C2) Capacity Factor (%)	11.93	100.54	103.23	103.92
(D1) Net MWH Not Gen. Due to Full Schedule Outages	607,386	0	0	0
(D2) % Net MWH Not Gen. Due to Full Schedule Outages	87.15	0	0	0
(E1) Net MWH Not Gen. Due to Partial Scheduled Outages	6,372	0	0	0
(E2) % Net MWH Not Gen. Due to Partial Scheduled Outages	0.92	0	0	0
(F1) Net MWH Not Gen Due to Full Forced Outages	0	0	0	0
(F2) % Net MWH Not Gen Due to Full Forced Outages	0	0	0	0
(G1) Net MWH Not Gen due to Partial Forced Outages	0	-3,743	-23,153	-22,111
(G2) % Net MWH Not Gen Due to Partial Forced Outages	0	-0.54	-3.23	-3.92
(H1) Net MWH Not Gen Due to Economic Dispatch	0	0	0	0
(H2) %Net MWH Not Gen Due to Economic Dispatch	0	0	0	0
(I1) Core Conservation	0	0	0	0
(I2) % Core Conservation	0	0	0	0
(J1) Net MWH Possible in Period	696,934	692,476	716,252	563,937
(J2) % Net mwh Possible in Period	100.00%	100.00%	100.00%	100.00%
(K) Equivalent Availability (%)	12.1	98.94	100	100
(L) Output Factor (%)	92.88	100.54	103.23	103.92
(M) Heat Rate (BTU/Net KWH)	8,616	10,481	10,109	10,122

Notes:
1) Fields (E1), (E2), (G1), (G2), (H1), (H2), (I1) and (I2) are estimates
2) Fields (D1), (D2), (F1) and (F2) include ramping losses
EAF is calculated using Standard NERC calculation and excludes OMC events

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2022

DEP Asheville CC

	ACC CT5	ACC ST6	Block Total
(A) MDC (mW)	190	90	280
(B) Period Hrs	743	743	743
(C) Net Generation (mWh)	128,380	65,897	194,277
(D) Capacity Factor (%)	90.94	98.54	93.38
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	13,745	1,857	15,603
(H) Scheduled Derates: percent of Period Hrs	9.74	2.78	7.50
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	0	0	0
(N) Economic Dispatch: percent of Period Hrs	0.00	0.00	0.00
(O) Net mWh Possible in Period	141,170	66,870	208,040
(P) Equivalent Availability (%)	90.26	97.22	92.50
(Q) Output Factor (%)	90.94	98.54	93.38
(R) Heat Rate (BTU/NkWh)	9,810	0	6,482

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2022

DEP Asheville CC

	ACC CT7	ACC ST8	Block Total
(A) MDC (mW)	190	90	280
(B) Period Hrs	743	743	743
(C) Net Generation (mWh)	99,671	50,114	149,785
(D) Capacity Factor (%)	70.60	74.94	72.00
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	13,745	1,857	15,603
(H) Scheduled Derates: percent of Period Hrs	9.74	2.78	7.50
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	27,754	14,899	42,652
(N) Economic Dispatch: percent of Period Hrs	19.66	22.28	20.50
(O) Net mWh Possible in Period	141,170	66,870	208,040
(P) Equivalent Availability (%)	90.26	97.22	92.50
(Q) Output Factor (%)	91.30	97.65	93.33
(R) Heat Rate (BTU/NkWh)	10,243	0	6,816

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2022

Lee Energy Complex

	Unit 1A	Unit 1B	Unit 1C	Unit ST1	Block Total
(A) MDC (mW)	225	227	228	379	1,059
(B) Period Hrs	743	743	743	743	743
(C) Net Generation (mWh)	118,789	117,362	118,623	191,923	546,697
(D) Capacity Factor (%)	71.06	69.58	70.02	68.16	69.48
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	54,702	54,702
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	19.43	6.95
(G) Net mWh Not Generated due to Partial Scheduled Outages	20,432	21,918	22,661	299	65,312
(H) Scheduled Derates: percent of Period Hrs	12.22	13.00	13.38	0.11	8.30
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	27,954	29,381	28,120	34,672	120,126
(N) Economic Dispatch: percent of Period Hrs	16.72	17.42	16.60	12.31	15.27
(O) Net mWh Possible in Period	167,175	168,661	169,404	281,597	786,837
(P) Equivalent Availability (%)	87.78	87.00	86.62	80.47	84.75
(Q) Output Factor (%)	71.06	69.58	70.02	84.59	74.67
(R) Heat Rate (BTU/NkWh)	9,842	9,809	9,717	3,868	7,710

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2022

Smith Energy Complex

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	193	193	184	570
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	109,932	109,663	125,473	345,068
(D) Capacity Factor (%)	76.66	76.47	91.78	81.48
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	15,231	15,231	4,829	35,292
(H) Scheduled Derates: percent of Period Hrs	10.62	10.62	3.53	8.33
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	18,236	18,505	6,410	43,150
(N) Economic Dispatch: percent of Period Hrs	12.72	12.90	4.69	10.19
(O) Net mWh Possible in Period	143,399	143,399	136,712	423,510
(P) Equivalent Availability (%)	89.38	89.38	96.47	91.67
(Q) Output Factor (%)	76.66	76.47	91.78	81.48
(R) Heat Rate (BTU/NkWh)	10,910	10,994	0	6,970

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2022

Smith Energy Complex

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	215	215	252	682
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	105,049	104,948	141,994	351,991
(D) Capacity Factor (%)	65.76	65.70	75.84	69.46
(E) Net mWh Not Generated due to Full Scheduled Outages	30,953	30,491	30,148	91,591
(F) Scheduled Outages: percent of Period Hrs	19.38	19.09	16.10	18.08
(G) Net mWh Not Generated due to Partial Scheduled Outages	11,082	11,122	623	22,827
(H) Scheduled Derates: percent of Period Hrs	6.94	6.96	0.33	4.50
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	12,661	13,184	14,471	40,317
(N) Economic Dispatch: percent of Period Hrs	7.93	8.25	7.73	7.96
(O) Net mWh Possible in Period	159,745	159,745	187,236	506,726
(P) Equivalent Availability (%)	73.69	73.95	83.57	77.42
(Q) Output Factor (%)	81.57	81.88	90.39	85.01
(R) Heat Rate (BTU/NkWh)	11,166	11,052	1,264	7,138

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2022

Sutton Energy Complex

	Unit 1A	Unit 1B	Unit ST1	Block Total
(A) MDC (mW)	224	224	271	719
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	119,527	122,382	143,854	385,763
(D) Capacity Factor (%)	71.82	73.53	71.44	72.21
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	20,061	19,689	1,857	41,608
(H) Scheduled Derates: percent of Period Hrs	12.05	11.83	0.92	7.79
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	26,844	24,361	55,642	106,846
(N) Economic Dispatch: percent of Period Hrs	16.13	14.64	27.63	20.00
(O) Net mWh Possible in Period	166,432	166,432	201,353	534,217
(P) Equivalent Availability (%)	87.95	88.17	99.08	92.21
(Q) Output Factor (%)	71.82	73.53	71.44	72.21
(R) Heat Rate (BTU/NkWh)	11,540	11,540	0	7,237

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Duke Energy Progress
Intermediate Power Plant Performance
Review Plan
March 2022

		Mayo Station
		Unit 1
(A)	**MDC (mW)**	713
(B)	**Period Hrs**	743
(C)	**Net Generation (mWh)**	79,056
(D)	**Net mWh Possible in Period**	529,759
(E)	**Equivalent Availability (%)**	88.70
(F)	**Output Factor (%)**	45.83
(G)	**Capacity Factor (%)**	14.92

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Intermediate Power Plant Performance
Review Plan
March 2022

Roxboro Station

		Unit 2	Unit 3	Unit 4
(A)	MDC (mW)	673	698	711
(B)	Period Hrs	743	743	743
(C)	Net Generation (mWh)	47,694	81,317	-3,293
(D)	Net mWh Possible in Period	500,039	518,614	528,273
(E)	Equivalent Availability (%)	75.31	97.78	40.14
(F)	Output Factor (%)	54.80	46.15	0.00
(G)	Capacity Factor (%)	9.54	15.68	0.00

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress Base Load Power Plant Performance Review Plan
Report Period: April 2021 - March 2022

	Brunswick 1	Brunswick 2	Harris 1	Robinson 2
(A) MDC (MW)	938	932	964	759
(B) Period Hours	8,760	8,760	8,760	8,760
(C1) Net Gen (MWH)	7,365,243	7,788,528	7,992,167	6,435,664
(C2) Capacity Factor (%)	89.64	95.4	94.64	96.79
(D1) Net MWH Not Gen. Due to Full Schedule Outages	607,386	92,377	548,403	0
(D2) % Net MWH Not Gen. Due to Full Schedule Outages	7.39	1.13	6.49	0
(E1) Net MWH Not Gen. Due to Partial Scheduled Outages	24,034	38,574	41,480	3,337
(E2) % Net MWH Not Gen. Due to Partial Scheduled Outages	0.29	0.47	0.49	0.05
(F1) Net MWH Not Gen Due to Full Forced Outages	293,281	147,816	12,693	277,136
(F2) % Net MWH Not Gen Due to Full Forced Outages	3.57	1.81	0.15	4.17
(G1) Net MWH Not Gen due to Partial Forced Outages	-73,064	97,025	-150,103	-67,297
(G2) % Net MWH Not Gen Due to Partial Forced Outages	-0.89	1.19	-1.77	-1.01
(H1) Net MWH Not Gen Due to Economic Dispatch	0	0	0	0
(H2) %Net MWH Not Gen Due to Economic Dispatch	0	0	0	0
(I1) Core Conservation	0	0	0	0
(I2) % Core Conservation	0	0	0	0
(J1) Net MWH Possible in Period	8,216,880	8,164,320	8,444,640	6,648,840
(J2) % Net mwh Possible in Period	100.00%	100.00%	100.00%	100.00%
(K) Equivalent Availability (%)	88.2	94.15	92.85	94.61
(L) Output Factor (%)	100.67	98.29	101.38	101
(M) Heat Rate (BTU/Net KWH)	10,422	10,647	10,226	10,284

Notes:
1) Fields (E1), (E2), (G1), (G2), (H1), (H2), (I1) and (I2) are estimates
2) Fields (D1), (D2), (F1) and (F2) include ramping losses
EAF is calculated using Standard NERC calculation and excludes OMC events

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2021 through March, 2022

DEP Asheville CC

	ACC CT5	ACC ST6	Block Total
(A) MDC (mW)	190	90	280
(B) Period Hrs	8,760	8,760	8,760
(C) Net Generation (mWh)	1,081,676	531,356	1,613,032
(D) Capacity Factor (%)	64.99	67.40	65.76
(E) Net mWh Not Generated due to Full Scheduled Outages	104,956	137,017	241,973
(F) Scheduled Outages: percent of Period Hrs	6.31	17.38	9.87
(G) Net mWh Not Generated due to Partial Scheduled Outages	178,965	20,319	199,284
(H) Scheduled Derates: percent of Period Hrs	10.75	2.58	8.12
(I) Net mWh Not Generated due to Full Forced Outages	2,052	23,009	25,061
(J) Forced Outages: percent of Period Hrs	0.12	2.92	1.02
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	296,751	76,699	373,451
(N) Economic Dispatch: percent of Period Hrs	17.83	9.73	15.23
(O) Net mWh Possible in Period	1,664,400	788,400	2,452,800
(P) Equivalent Availability (%)	82.82	77.13	80.99
(Q) Output Factor (%)	89.39	98.55	92.22
(R) Heat Rate (BTU/NkWh)	10,077	0	6,758

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2021 through March, 2022

DEP Asheville CC

	ACC CT7	ACC ST8	Block Total
(A) MDC (mW)	190	90	280
(B) Period Hrs	8,760	8,760	8,760
(C) Net Generation (mWh)	1,289,252	659,704	1,948,956
(D) Capacity Factor (%)	77.46	83.68	79.46
(E) Net mWh Not Generated due to Full Scheduled Outages	104,874	44,997	149,871
(F) Scheduled Outages: percent of Period Hrs	6.30	5.71	6.11
(G) Net mWh Not Generated due to Partial Scheduled Outages	176,634	23,849	200,483
(H) Scheduled Derates: percent of Period Hrs	10.61	3.02	8.17
(I) Net mWh Not Generated due to Full Forced Outages	6,514	753	7,267
(J) Forced Outages: percent of Period Hrs	0.39	0.10	0.30
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	87,126	59,098	146,224
(N) Economic Dispatch: percent of Period Hrs	5.23	7.50	5.96
(O) Net mWh Possible in Period	1,664,400	788,400	2,452,800
(P) Equivalent Availability (%)	82.70	91.17	85.42
(Q) Output Factor (%)	88.48	96.06	90.91
(R) Heat Rate (BTU/NkWh)	10,100	0	6,681

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2021 through March, 2022

Lee Energy Complex

	Unit 1A	Unit 1B	Unit 1C	Unit ST1	Block Total
(A) MDC (mW)	225	227	228	379	1,059
(B) Period Hrs	8,760	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,232,981	1,320,297	1,293,666	2,465,613	6,312,557
(D) Capacity Factor (%)	62.56	66.40	64.77	74.26	68.05
(E) Net mWh Not Generated due to Full Scheduled Outages	256,099	72,689	150,594	256,394	735,775
(F) Scheduled Outages: percent of Period Hrs	12.99	3.66	7.54	7.72	7.93
(G) Net mWh Not Generated due to Partial Scheduled Outages	239,663	278,755	280,108	18,430	816,957
(H) Scheduled Derates: percent of Period Hrs	12.16	14.02	14.02	0.56	8.81
(I) Net mWh Not Generated due to Full Forced Outages	2,108	50,069	11,430	14,768	78,375
(J) Forced Outages: percent of Period Hrs	0.11	2.52	0.57	0.44	0.84
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	4,230	4,230
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.13	0.05
(M) Net mWh Not Generated due to Economic Dispatch	239,231	266,710	261,481	560,605	1,328,027
(N) Economic Dispatch: percent of Period Hrs	12.14	13.41	13.09	16.89	14.32
(O) Net mWh Possible in Period	1,971,000	1,988,520	1,997,280	3,320,040	9,276,840
(P) Equivalent Availability (%)	74.74	79.81	77.86	91.15	82.37
(Q) Output Factor (%)	72.00	70.78	70.82	80.87	74.68
(R) Heat Rate (BTU/NkWh)	9,813	9,885	9,797	3,541	7,375

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2021 through March, 2022

Smith Energy Complex

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	193	193	184	570
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	963,844	1,016,606	1,130,259	3,110,709
(D) Capacity Factor (%)	57.01	60.13	70.12	62.30
(E) Net mWh Not Generated due to Full Scheduled Outages	331,876	312,441	313,849	958,167
(F) Scheduled Outages: percent of Period Hrs	19.63	18.48	19.47	19.19
(G) Net mWh Not Generated due to Partial Scheduled Outages	165,410	166,065	55,477	386,952
(H) Scheduled Derates: percent of Period Hrs	9.78	9.82	3.44	7.75
(I) Net mWh Not Generated due to Full Forced Outages	6,758	3,394	0	10,152
(J) Forced Outages: percent of Period Hrs	0.40	0.20	0.00	0.20
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	1,424	1,424
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.09	0.03
(M) Net mWh Not Generated due to Economic Dispatch	222,558	191,935	110,831	525,323
(N) Economic Dispatch: percent of Period Hrs	13.16	11.35	6.88	10.52
(O) Net mWh Possible in Period	1,690,680	1,690,680	1,611,840	4,993,200
(P) Equivalent Availability (%)	70.19	71.50	77.00	72.83
(Q) Output Factor (%)	77.31	77.34	89.83	81.44
(R) Heat Rate (BTU/NkWh)	11,182	11,226	0	7,133

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2021 through March, 2022

Smith Energy Complex

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	215	215	252	682
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,221,848	1,262,804	1,630,077	4,114,729
(D) Capacity Factor (%)	64.87	67.05	73.84	68.87
(E) Net mWh Not Generated due to Full Scheduled Outages	215,412	220,156	269,720	705,288
(F) Scheduled Outages: percent of Period Hrs	11.44	11.69	12.22	11.81
(G) Net mWh Not Generated due to Partial Scheduled Outages	172,149	173,623	4,356	350,129
(H) Scheduled Derates: percent of Period Hrs	9.14	9.22	0.20	5.86
(I) Net mWh Not Generated due to Full Forced Outages	16,899	10,291	0	27,190
(J) Forced Outages: percent of Period Hrs	0.90	0.55	0.00	0.46
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	6,712	6,712
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.30	0.11
(M) Net mWh Not Generated due to Economic Dispatch	257,092	216,525	296,656	770,272
(N) Economic Dispatch: percent of Period Hrs	13.65	11.50	13.44	12.89
(O) Net mWh Possible in Period	1,883,400	1,883,400	2,207,520	5,974,320
(P) Equivalent Availability (%)	78.52	78.55	87.28	81.77
(Q) Output Factor (%)	80.80	80.99	87.97	83.56
(R) Heat Rate (BTU/NkWh)	10,680	11,176	1,790	7,310

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2021 through March, 2022

Sutton Energy Complex

	Unit 1A	Unit 1B	Unit ST1	Block Total
(A) MDC (mW)	224	224	271	719
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,288,891	1,316,487	1,567,398	4,172,776
(D) Capacity Factor (%)	65.68	67.09	66.02	66.25
(E) Net mWh Not Generated due to Full Scheduled Outages	152,843	161,295	188,340	502,478
(F) Scheduled Outages: percent of Period Hrs	7.79	8.22	7.93	7.98
(G) Net mWh Not Generated due to Partial Scheduled Outages	240,601	238,640	34,797	514,038
(H) Scheduled Derates: percent of Period Hrs	12.26	12.16	1.47	8.16
(I) Net mWh Not Generated due to Full Forced Outages	33,764	0	122	33,886
(J) Forced Outages: percent of Period Hrs	1.72	0.00	0.01	0.54
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	23,266	23,266
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.98	0.37
(M) Net mWh Not Generated due to Economic Dispatch	246,141	245,818	560,036	1,051,995
(N) Economic Dispatch: percent of Period Hrs	12.54	12.53	23.59	16.70
(O) Net mWh Possible in Period	1,962,240	1,962,240	2,373,960	6,298,440
(P) Equivalent Availability (%)	78.23	79.62	89.62	82.95
(Q) Output Factor (%)	73.21	73.94	72.31	73.10
(R) Heat Rate (BTU/NkWh)	11,540	11,514	0	7,197

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership

Duke Energy Progress
Intermediate Power Plant
Performance Review Plan
April, 2021 through March, 2022

Mayo Station

Units	Unit 1
(A) MDC (mW)	713
(B) Period Hrs	8,760
(C) Net Generation (mWh)	1,042,234
(D) Net mWh Possible in Period	6,245,880
(E) Equivalent Availability (%)	48.88
(F) Output Factor (%)	48.00
(G) Capacity Factor (%)	16.69

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Intermediate Power Plant
Performance Review Plan
April, 2021 through March, 2022

Roxboro Station

Units	Unit 2	Unit 3	Unit 4
(A) MDC (mW)	673	698	711
(B) Period Hrs	8,760	8,760	8,760
(C) Net Generation (mWh)	1,111,902	2,270,096	1,464,980
(D) Net mWh Possible in Period	5,895,480	6,114,480	6,228,360
(E) Equivalent Availability (%)	73.31	75.42	50.02
(F) Output Factor (%)	60.60	64.83	66.03
(G) Capacity Factor (%)	18.86	37.13	23.52

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 1**
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs	7,921,117	7,173,379	8,347,081	6,160,075	29,601,651
Cost	$ 51,270,186	$ 45,255,131	$ 44,441,262	$ 35,236,362	$ 176,202,941
$/MWhs	$ 6.47	$ 6.31	$ 5.32	$ 5.72	
Avg. $/MWhs					**$ 5.9525**
Cents per kWh					**0.5952**

	GWhs	Capacity Rating MDC	Hours	Proposed Nuclear Capacity Factor
Brunswick 1	7,921	938	8,760	96.40%
Brunswick 2	7,173	932	8,760	87.86%
Harris 1	8,347	964	8,760	98.84%
Robinson 1	6,160	759	8,760	92.65%
	29,602	3,593	8,760	**94.05%**

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 2**
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs with NERC applied	7,758,378	7,708,751	7,866,182	6,092,997	29,426,308
Hours in Year	8,760	8,760	8,760	8,760	8,760
MDC	938	932	964	759	3,593
Capacity Factor-NERC 5yr Avg	0.9442	0.9442	0.9315	0.9164	
Cost ($)	$ 46,181,513	$ 45,886,109	$ 46,823,213	$ 36,268,382	$ 175,159,216
$/MWhs	$ 5.95	$ 5.95	$ 5.95	$ 5.95	
Avg. $/MWHs					**$ 5.95**
Cents per kWh					**0.5952**

	Capacity Rating MDC	NCF Rating	Weighted Average
Brunswick 1	938	94.42%	24.65%
Brunswick 2	932	94.42%	24.49%
Harris 1	964	93.15%	24.99%
Robinson 1	759	91.64%	19.36%
	3,593		**93.49%**

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 3**
North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation in MWhs
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Resource Type		**MWh Dec'22-Nov'23**
Nuclear		29,601,651
Coal		9,087,592
Gas CT and CC Total		19,494,222
Total Hydro		667,442
Utility Owned Solar Generation		264,499
Total Net Generation		59,115,406
Purchases for REPS Compliance	2,103,148	
Purchases from Qualifying Facilities	5,128,797	
Purchases from Dispatchable Units	1,977,042	
Emergency & DSM Purchases	1,292	
Allocated Economic Purchases	321,417	
Joint Dispatch Fuel Transfer Purchases	762,722	10,294,418
Total Net Generation and Purchases		69,409,824
Sales Totals (intersystem sales)	(120,266)	
Fuel Transfer Sales (JDA & economic sales)	(5,382,711)	(5,502,977)
Line Losses and Company Use		(2,364,858)
Total NC System Sales		**61,541,989**

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 4**
North Carolina Annual Fuel and Fuel Related Expense
Fuel Costs ($)
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Resource Type		**Costs $ Dec'22-Nov'23**
Nuclear		$ 176,202,941
Coal		351,295,882
Reagent and By-Product Costs		47,259,477
Gas CT and CC Total		740,683,337
Total Hydro		-
Utility Owned Solar Generation		-
Total Generation Costs		1,315,441,637
Purchases for REPS Compliance Energy	$ 116,315,118	
Purchases for REPS Compliance Capacity	23,896,105	
Purchases from Qualifying Facilities Energy	224,803,592	
Purchases from Qualifying Facilities Capacity	46,050,571	
Purchases from Dispatchable Units Energy	88,434,734	
Emergency & DSM Purchases	63,494	
Allocated Economic Purchases	21,400,024	
Joint Dispatch Fuel Transfer Purchases	26,494,604	
Joint Dispatch Savings	(37,582,671)	$ 509,875,571
Total Net Generation and Purchases		1,825,317,208
Sales Totals (intersystem sales)	$ (4,189,289)	
Fuel Transfer Sales (JDA & economic sales)	(209,547,418)	(213,736,707)
Total System Fuel and Related Expenses		**$ 1,611,580,501**

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Reagents ($)
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Workpaper 5

Month	Year	Ammonia/ Urea	Lime, Hydrated Lime & Limestone	Limestone Off-System Sales	Magnesium Hydroxide	Calcium Carbonate	Total NC System Reagent Cost	Gypsum (Gain)/Loss	Ash (Gain)/Loss	Total NC System Reagent Cost and ByProduct (Gain)/Loss
December	2022	$ 757,827	$ 2,229,993	$ (30,358)	$ 563,226	$ 429,932	$ 3,950,619	$ (286,246)	$ 1,992,697	$ 5,657,070
January	2023	800,641	2,452,984	(42,279)	556,600	429,710	4,197,657	(340,668)	1,313,835	5,170,824
February	2023	726,279	2,262,676	(46,075)	501,466	391,443	3,835,788	8,077,229	2,056,718	13,969,735
March	2023	432,373	1,400,184	(73,878)	287,081	239,335	2,285,096	(216,184)	1,434,688	3,503,599
April	2023	187,843	589,451	(77,509)	144,323	102,765	946,872	(79,651)	1,987,377	2,854,598
May	2023	130,829	380,815	(62,990)	107,090	68,892	624,636	(43,618)	1,367,291	1,948,309
June	2023	211,433	630,140	(44,565)	152,513	117,193	1,066,715	(82,494)	1,604,312	2,588,533
July	2023	360,499	1,138,169	(51,069)	244,201	204,171	1,895,971	(179,113)	1,256,208	2,973,065
August	2023	328,008	1,027,242	(64,356)	221,699	185,609	1,698,201	(156,341)	1,674,864	3,216,723
September	2023	134,103	366,975	(39,694)	92,755	72,768	626,907	(38,265)	1,272,319	1,860,960
October	2023	21,814	66,470	(16,282)	18,058	11,609	101,669	(6,309)	1,523,904	1,619,264
November	2023	130,671	349,206	(49,287)	84,318	70,009	584,916	(38,020)	1,349,900	1,896,796
12ME Nov	2023	$ 4,222,321	$ 12,894,304	$ (598,343)	$ 2,973,330	$ 2,323,434	$ 21,815,046	$ 6,610,319	$ 18,834,112	$ 47,259,477

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Fuel Impacts
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Workpaper 6

		Positive numbers represent expense, Negative numbers represent revenues							
		Allocated Economic Purchase Cost		Economic Sales Cost		Fuel Transfer Payment		JDA Savings Payment	
Month	**Year**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**
December	2022	$ 635,208	$ 909,298	$ (10,807,450)	$ (19,309,194)	$ 956,745	$ (956,745)	$ 1,244,114	$ (1,244,114)
January	2023	7,481,126	10,741,410	(9,505,674)	(16,313,672)	(4,642,214)	4,642,214	(889,882)	889,882
February	2023	1,753,138	2,577,259	(9,935,974)	(16,408,828)	(4,803,704)	4,803,704	(783,616)	783,616
March	2023	945,712	1,342,360	(7,117,062)	(5,238,612)	(17,106,661)	17,106,661	(2,754,045)	2,754,045
April	2023	2,128,499	3,198,121	(3,525,026)	(1,381,234)	(20,443,700)	20,443,700	(7,429,686)	7,429,686
May	2023	1,173,295	1,722,930	(3,491,999)	(901,705)	(22,912,103)	22,912,103	(6,720,337)	6,720,337
June	2023	1,715,177	2,509,727	(2,905,192)	(2,453,225)	(6,866,520)	6,866,520	(8,066,444)	8,066,444
July	2023	2,066,224	2,912,248	(3,855,116)	(5,428,202)	(8,265,640)	8,265,640	(3,760,075)	3,760,075
August	2023	1,453,301	2,128,553	(3,478,531)	(4,913,581)	(9,768,913)	9,768,913	(2,715,754)	2,715,754
September	2023	1,348,253	1,933,109	(2,225,274)	(2,232,322)	(5,068,150)	5,068,150	(574,466)	574,466
October	2023	171,814	245,362	(2,806,367)	(2,875,687)	(8,842,615)	8,842,615	(2,671,178)	2,671,178
November	2023	528,277	792,674	(3,716,631)	(4,015,498)	(11,919,042)	11,919,042	(2,461,302)	2,461,302
Total		$ 21,400,024		$ (63,370,297)		$ (119,682,517)		$ (37,582,671)	

Note: Totals may not sum due to rounding

		Fuel Transfer Payments	
		Purchases	**Sales**
December	2022	$ 5,161,607	$ 4,204,862
January	2023	4,600,236	9,242,451
February	2023	3,487,003	8,290,707
March	2023	830,528	17,937,189
April	2023	730,777	21,174,477
May	2023	324,588	23,236,691
June	2023	1,547,095	8,413,615
July	2023	2,356,851	10,622,491
August	2023	2,203,602	11,972,515
September	2023	2,982,302	8,050,452
October	2023	1,582,848	10,425,463
November	2023	687,167	12,606,209
		$ 26,494,604	$ 146,177,121
			$ (119,682,517)

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Payments
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Workpaper 7

		MWh Transfer Projection		MWh Purchase Allocation Delta		Adjusted MWh Transfer		Fossil Gen Cost $/MWh		Pre-Net Payments $		Actual Payments $	
Month	**Year**	**DEP to DEC**	**DEC to DEP**	**DEP**	**DEC**	**DEP to DEC**	**DEC to DEP**	**DEP**	**DEC**	**DEP to DEC**	**DEC to DEP**	**DEP to DEC**	**DEC to DEP**
December	2022	83,133	99,947	(7,533)	7,533	83,133	107,480	$ 50.58	$ 48.02	$ 5,161,607	$ 4,204,862	$ 956,745	$ -
January	2023	173,512	78,330	(15,047)	15,047	173,512	93,377	$ 53.27	$ 49.27	4,600,236	9,242,451	-	4,642,214
February	2023	159,544	65,463	(7,067)	7,067	159,544	72,529	$ 51.96	$ 48.08	3,487,003	8,290,707	-	4,803,704
March	2023	385,018	17,149	(4,647)	4,647	385,018	21,796	$ 46.59	$ 38.10	830,528	17,937,189	-	17,106,661
April	2023	526,671	29,617	26,394	(26,394)	553,065	29,617	$ 38.29	$ 24.67	730,777	21,174,477	-	20,443,700
May	2023	669,492	11,212	20,269	(20,269)	689,761	11,212	$ 33.69	$ 28.95	324,588	23,236,691	-	22,912,103
June	2023	229,074	54,729	(771)	771	229,074	55,500	$ 36.73	$ 27.88	1,547,095	8,413,615	-	6,866,520
July	2023	338,648	80,491	9,086	(9,086)	347,734	80,491	$ 30.55	$ 29.28	2,356,851	10,622,491	-	8,265,640
August	2023	379,078	79,781	15,948	(15,948)	395,026	79,781	$ 30.31	$ 27.62	2,203,602	11,972,515	-	9,768,913
September	2023	331,038	120,648	4,083	(4,083)	335,121	120,648	$ 24.02	$ 24.72	2,982,302	8,050,452	-	5,068,150
October	2023	526,088	65,488	2,345	(2,345)	528,434	65,488	$ 19.73	$ 24.17	1,582,848	10,425,463	-	8,842,615
November	2023	417,235	24,801	1,561	(1,561)	418,796	24,801	$ 30.10	$ 27.71	687,167	12,606,209	-	11,919,042
Total		4,218,531	727,656	44,621	(44,621)	4,298,217	762,722			$ 26,494,604	$ 146,177,121	$ 956,745	$ 120,639,262

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Workpaper 8

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC Retail			
Residential	16,637,596		16,637,596
Small General Service	1,797,603		1,797,603
Medium General Service	10,360,942		10,360,942
Large General Service	9,189,937		9,189,937
Lighting	379,481		379,481
NC Retail	38,365,559		38,365,559
SC Retail	6,142,464	33,949	6,176,414
Total Wholesale	17,033,967		17,033,967
Total Adjusted NC System Sales	61,541,989	33,949	61,575,939
NC as a percentage of total	62.34%	0.00%	62.31%
SC as a percentage of total	9.98%	100.00%	10.03%
Wholesale as a percentage of total	27.68%	0.00%	27.66%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		33,949	
Marginal Fuel rate per MWh for SC NEM	$	22.44	
Fuel Benefit to be directly assigned to SC	$	761,935	
System Fuel Expense	$	1,611,580,501	Exh 2 Sch 1 Pg 1
Fuel benefit to be directly assigned to SC Retail		761,935	
Total Adjusted System Fuel Expense	$	1,612,342,436	Exh 2 Sch 1 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Normalized Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Workpaper 9

	Test Period Sales MWhs	Weather Normalization	Customer Growth	Remove impact of SC DERP Net Metered Generation	Normalized Test Period Sales MWhs
NC Retail					
Residential	16,261,952	389,695	140,949		16,792,596
Small General Service	1,895,276	36,179	24,960		1,956,415
Medium General Service	10,425,247	152,223	(108,685)		10,468,785
Large General Service	8,339,752	(135,279)	(2,374)		8,202,098
Lighting	319,438	0	883		320,322
NC Retail	37,241,666	442,818	55,732		37,740,216
SC Retail	5,940,149	64,104	63,746	33,949	6,101,948
Total Wholesale	17,378,061	212,368	147,053		17,737,481
Total Adjusted NC System Sales	60,559,875	719,290	266,531	33,949	61,579,645
NC as a percentage of total	61.50%				61.29%
SC as a percentage of total	9.81%				9.91%
Wholesale as a percentage of total	28.70%				28.80%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs		33,949	
Marginal Fuel rate per MWh for SC NEM	$	22.44	
Fuel Benefit to be directly assigned to SC	$	761,935	
System Fuel Expense	$	1,611,729,522	Exh 2 Sch 2 Pg 1
Fuel benefit to be directly assigned to SC Retail		761,935	
Total Adjusted System Fuel Expense	$	1,612,491,458	Exh 2 Sch 2 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Adjustment - MWh
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Harrington Workpaper 9a

		Residential MWH Adjustment	Small Gen Service MWH Adjustment	Medium Gen Service MWH Adjustment	Large Gen Service MWH Adjustment	NC Retail MWH Adjustment	SC Retail MWH Adjustment	Wholesale MWH Adjustment	Total MWH Adjustment
April	**2021**	57,996	32	3,618	11,066	72,711	13,122	-	85,833
May	**2021**	(18,139)	(752)	(5,439)	(6,711)	(31,041)	(5,231)	14,690	(21,582)
June	**2021**	(33,400)	(2,210)	(10,890)	(4,641)	(51,141)	(7,017)	7,305	(50,853)
July	**2021**	10,479	597	3,154	2,031	16,260	2,309	30,047	48,616
August	**2021**	(23,687)	(1,594)	(8,398)	(5,458)	(39,137)	(5,985)	(82,140)	(127,262)
September	**2021**	(99,742)	(8,126)	(40,493)	(20,623)	(168,984)	(23,002)	(17,415)	(209,401)
October	**2021**	(68,811)	(6,022)	(34,425)	(31,029)	(140,288)	(22,138)	(63,013)	(225,439)
November	**2021**	11,588	52,760	235,538	6,176	306,063	39,169	(33,771)	311,461
December	**2021**	51,592	-	-	-	51,592	6,788	264,220	322,600
January	**2022**	188,487	2,708	15,160	11,059	217,414	30,795	(112,867)	135,342
February	**2022**	(87,820)	(1,214)	(5,602)	(97,147)	(191,783)	(15,795)	97,277	(110,301)
March	**2022**	401,152	-	-	-	401,152	51,089	108,035	560,276
12ME March	**2022**	**389,695**	**36,179**	**152,223**	**(135,279)**	**442,818**	**64,104**	**212,368**	**719,290**

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment - MWh
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Harrington Workpaper 9b

Rate Schedule	Estimation Method[1]	Reference	NC Proposed MWH Adjustment[1]	SC Proposed MWH Adjustment[1]	Wholesale Proposed MWH Adjustment
Residential	Regression	RES	140,949	(2,989)	
General:					
General Service Small	Regression	SGS	24,960	(1,877)	
General Service Medium	Customer	MGS	(108,685)	3,610	
Total General			(83,726)	1,734	
Lighting:					
Street Lighting	Regression	SLS/SLR	754	28	
Sports Field Lighting	Regression	SFLS	95	(9)	
Traffic Signal Service	Regression	TSS/TFS	35	64,983	
Total Street Lighting			883	65,001	
Industrial:					
I - Textile	Customer	LGS	-	-	
I - Nontextile		LGS	(2,374)	-	
Total Industrial			(2,374)	-	
Total			**55,732**	**63,746**	**147,053**

Note:

[1] Two approved methods are used for estimating the growth adjustment depending on the class/schedule:

"Regression" refers to the use of Ordinary Least Squares Regression.

"Customer" refers to the use of the Customer by Customer approach.

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales - NERC 5 year Average
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Workpaper 10

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC Retail			
Residential	16,637,596		16,637,596
Small General Service	1,797,603		1,797,603
Medium General Service	10,360,942		10,360,942
Large General Service	9,189,937		9,189,937
Lighting	379,481		379,481
NC Retail	38,365,559		38,365,559
SC Retail	6,142,464	33,949	6,176,414
Total Wholesale	17,033,967		17,033,967
Total Adjusted NC System Sales	61,541,989	33,949	61,575,939
NC as a percentage of total	62.34%	0.00%	62.31%
SC as a percentage of total	9.98%	100.00%	10.03%
Wholesale as a percentage of total	27.68%	0.00%	27.66%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		33,949	
Marginal Fuel rate per MWh for SC NEM	$	22.44	
Fuel Benefit to be directly assigned to SC	$	761,935	
System Fuel Expense	$	1,617,314,958	Exh 2 Sch 3 Pg 1
Fuel benefit to be directly assigned to SC Retail		761,935	
Total Adjusted System Fuel Expense	$	1,618,076,893	Exh 2 Sch 3 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
NC Retail Allocation %
Line Loss Calculation Factors - 12 Months Ending December 31, 2021
Docket No. E-2, Sub 1292

Harrington Workpaper 11

Generator Step Up Loss % 0.2027%

	KWh at Meter	KWh at Meter Allocation	KWh at at Generation (high side of GSU)	kWh at Generation Allocation	Losses
NC RES	16,077,345,283	26.35%	16,719,402,796	26.61%	642,057,513
NC RES-TOU	409,519,286	0.67%	425,873,661	0.68%	16,354,375
NC SGS	1,843,752,161	3.02%	1,917,370,269	3.05%	73,618,108
NC SGS-CLR	50,348,689	0.08%	52,358,856	0.08%	2,010,167
NC MGS-TOU	7,941,197,311	13.01%	8,243,478,564	13.12%	302,281,253
NC MGS	2,610,660,982	4.28%	2,712,570,386	4.32%	101,909,404
NC SI	39,179,246	0.06%	40,574,714	0.06%	1,395,467
NC LGS	903,719,021	1.48%	932,791,202	1.48%	29,072,181
NC LGS-TOU	1,807,525,367	2.96%	1,862,061,380	2.96%	54,536,014
NC LGS-RTP	5,669,674,229	9.29%	5,812,356,842	9.25%	142,682,613
NC TSS	4,429,584	0.01%	4,606,482	0.01%	176,898
NC ALS	248,843,587	0.41%	258,781,291	0.41%	9,937,704
NC SLS	83,722,836	0.14%	87,066,353	0.14%	3,343,517
NC SFLS	1,502,267	0.00%	1,548,762	0.00%	46,495
Total NCR	37,691,419,849	61.76%	39,070,841,558	62.18%	1,379,421,708
NCWHS incl. NCEMPA	17,295,487,365	28.34%	17,524,142,568	27.89%	228,655,203
Total NC	54,986,907,215	90.11%	56,594,984,126	90.07%	1,608,076,911
SC RES	2,045,146,311	3.35%	2,126,820,339	3.38%	81,674,028
SC RES-TOU	32,636,400	0.05%	33,939,753	0.05%	1,303,352
SC SGS	249,818,818	0.41%	259,780,688	0.41%	9,961,870
SC SGS-CLR	5,783,201	0.01%	6,014,156	0.01%	230,955
SC MGS-TOU	1,054,238,991	1.73%	1,094,119,186	1.74%	39,880,195
SC MGS	485,236,273	0.80%	503,805,531	0.80%	18,569,258
SC SI	13,354,534	0.02%	13,823,888	0.02%	469,354
SC LGS	497,495,020	0.82%	513,126,765	0.82%	15,631,745
SC LGS-TOU	227,506,426	0.37%	233,078,732	0.37%	5,572,306
SC LGS-CRTL-TOU	673,135,674	1.10%	686,670,823	1.09%	13,535,149
SC LGS-RTP	678,331,040	1.11%	692,997,994	1.10%	14,666,953
SC TSS	1,926,224	0.00%	2,003,148	0.00%	76,925
SC ALS	57,773,877	0.09%	60,081,108	0.10%	2,307,231
SC SLS	14,864,833	0.02%	15,458,469	0.02%	593,635
SC SFLS	139,620	0.00%	143,936	0.00%	4,315
Total SCR	6,037,387,243	9.89%	6,241,864,514	9.93%	204,477,271
SCWHS		0.00%		0.00%	0
Total SC	6,037,387,243	9.89%	6,241,864,514	9.93%	204,477,271
Total System	61,024,294,458	100.00%	62,836,848,640	100.00%	1,812,554,182

Cost of Service Data Summarized

	kWh @ Meter	kWh @ Generator	Losses (kWh)	Loss Percent
Residential	16,486,864,569	17,180,101,925	693,237,356	4.2050%
SGS	1,898,530,434	1,978,345,876	79,815,441	4.2040%
MGS	10,591,037,539	11,018,959,994	427,922,455	4.0400%
LGS	8,380,918,616	8,624,692,379	243,773,762	2.9090%
Lighting	334,068,691	348,102,037	14,033,347	4.2010%
Total NC Retail	37,691,419,849	39,150,202,210	1,458,782,361	3.8700%
Total NC Retail	37,691,419,849	39,150,202,210	1,458,782,361	3.8700%
SC Retail	6,037,387,243	6,254,542,983	217,155,740	3.5970%
12ME NEM Generation	33,058,923	34,248,052	1,189,129	3.5970%
Total SC Retail	6,070,446,166	6,288,791,035	218,344,870	3.5970%
Wholesale	17,262,428,442	17,525,489,536	263,061,094	1.5240%
Total System	61,024,294,458	62,964,482,782	1,940,188,324	3.1790%

Line Loss Calculations for Projected Fuel Costs	**MWh @ Meter**	**MWh @ Generator**	**Losses (MWh)**	**Loss Percent**
Total NC Retail	38,365,559	39,910,079	1,544,520	4.0260%
Total SC Retail	6,176,414	6,406,869	230,455	3.7310%
Wholesale	17,033,967	17,297,582	263,615	1.5480%
Total System	61,575,939	63,614,529	2,038,590	3.3110%
Allocation percent - NC retail	62.31%	62.74%		

Line Loss Calculations for Normalized Test Period Sales	**MWh @ Meter**	**MWh @ Generator**	**Losses (MWh)**	**Loss Percent**
Total NC Retail	37,740,216	39,259,561	1,519,345	4.0260%
Total SC Retail	6,101,948	6,329,625	227,677	3.7310%
Wholesale	17,737,481	18,011,984	274,503	1.5480%
Total System	61,579,645	63,601,170	2,021,524	3.2830%
Allocation percent - NC retail	61.29%	61.73%		

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Derivation of Equal Percent Increases for all Rate Classes
Annualized Revenues at Current Rates
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Harrington Workpaper 12

									Remove Partial Year Impacts						Add Impact of Approved Rate Changes During Test Year					
Revenue Class (1)	Annual Sales (2)	Annual EE Opt-Out Sales (3)	Annual DSM Opt-Out Sales (4)	Annual Customer Count (5)	Annual Rider JAA kWh Units (6)	Annual Rider JAA Demand Units (7)	Annual Customer Count (Adjusted for Premise Billing) (8) = (5) adjusted	Annual Revenues (9)	Test Year Rate Changes** (10) - See Annualization Adjustment Worksheet	Opt-Out Credit Due to Jan 2021 EE Rate (11)	Opt-Out Credit Due to Jan. 2021 DSM Rate (12)	NC Rate Case (13)	REPS Revenue Due to December 2020 Rate Change (14)	Annual Revenues Excluding All Rate Adjustments (15)=(9)-[10-11-12]-(13)-(14)	Annual Impact of Rate Changes*** (16) See Annualization Adjustment worksheet	Annual Opt-Out Impact of 1/21 EE Rate (17) = (3) * Rate Change	Annual Opt-Out Impact of 1/21 EE Rate (18) = (4) * Rate Change	NC Rate Case (19) per Report PMCM7M Worksheet	Annual Impact of Dec. 2020 REPS Rate (20) = (8) * Rate Change	Annual Revenue At Current Rates (21)=(15)+[16-17-18]+(19)+(20)
Residential	16,328,296,167	0	0	16,138,913	16,328,296,167	0	16,230,813	$1,933,801,212	$12,035,543	$0	$0	$0	$459,280	$1,921,306,388	$176,127,295	$0	$0	$0	$1,947,698	$2,099,381,381
Residential	16,263,344,918	0	0	15,390,699	16,263,344,918	0	15,501,404	$1,910,802,434	$11,991,468	$0	$0	$0	$457,213	$1,898,353,752	$175,702,582	$0	$0	$0	$1,860,168	$2,075,916,503
SGS	1,134,747	0	0	8	1,134,747	0	0	$315,904	$0	$0	$0	$0	$0	$315,904	$7	$0	$0	$0	$0	$315,911
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lighting	63,816,502	0	0	748,206	63,816,502	0	729,409	$22,682,874	$44,075	$0	$0	$0	$2,067	$22,636,732	$424,706	$0	$0	$0	$87,529	$23,148,967
Commercial	11,807,584,019	5,592,864,960	5,631,657,351	2,546,718	2,086,751,642	30,735,276	2,630,400	$1,091,274,503	$2,486,169	($455,540)	($203,335)	$0	$256,613	$1,087,872,846	$50,172,452	($1,254,709)	($557,776)	$0	$1,104,768	$1,140,962,551
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$25	$0	$0	$0	$0	$25
SGS	1,866,734,879	479,644,770	486,584,144	2,078,439	1,824,392,536	0	2,104,570	$237,561,721	$800,915	($89,571)	($39,156)	$0	$203,839	$236,428,240	$17,572,674	($110,318)	($48,658)	$0	$883,919	$255,043,810
MGS	8,649,094,048	4,033,355,130	4,017,617,603	450,807	66,020,345	28,392,626	505,955	$720,682,120	$1,633,760	($337,246)	($146,417)	$0	$41,482	$718,523,215	$30,975,673	($927,672)	($401,762)	$0	$212,501	$751,040,823
LGS	1,095,416,332	1,026,220,294	1,073,558,887	1,224	0	2,342,650	1,788	$82,185,930	$3,127	($40,853)	($17,762)	$0	$89	$82,124,099	$750,103	($236,031)	($107,356)	$0	$751	$83,218,339
Lighting	196,338,761	53,644,766	53,896,716	16,248	196,338,761	0	18,086	$50,844,732	$48,367	$12,131	($0)	$0	$11,203	$50,797,293	$873,977	$19,312	$0	$0	$7,596	$51,659,554
Industrial	7,896,099,614	8,149,837,928	8,138,222,184	39,283	2,333,065,567	18,538,276	30,063	$522,057,723	$622,821	($289,513)	($126,200)	$0	$8,009	$521,011,180	$9,137,207	($1,870,095)	($813,076)	$0	$46,297	$532,877,856
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	16,659,296	10,415,981	10,467,949	11,324	61,266	0	6,700	$1,958,710	$6,476	($908)	($395)	$0	$1,649	$1,949,282	$153,822	($2,396)	($1,047)	$0	$10,318	$2,116,865
MGS	1,954,145,557	1,597,642,370	1,589,136,156	25,497	1,568,002,259	5,829,140	10,693	$149,973,490	$309,017	($66,891)	($29,083)	$0	$2,721	$149,565,778	$6,031,301	($367,458)	($158,914)	$0	$16,467	$156,139,917
LGS	5,913,108,245	6,534,377,429	6,531,158,530	2,462	752,815,527	12,709,136	12,670	$367,347,415	$305,259	($222,462)	($96,723)	$0	$3,190	$366,719,781	$2,899,695	($1,502,907)	($653,116)	$0	$19,512	$371,795,010
Lighting	12,186,516	7,402,149	7,459,550	0	12,186,516	0	0	$2,778,109	$2,069	$748	$0	$0	$448	$2,776,339	$52,389	$2,665	$0	$0	$0	$2,826,063
Public Streets & Highways	63,035,556	0	0	9,403	3,912,494	0	16,249	$18,131,665	$5,373	$0	$0	$0	$2,103	$18,124,189	$227,849	$0	$0	$0	$6,825	$18,358,862
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	3,994,713	0	0	6,148	3,912,494	0	11,262	$424,668	$592	$0	$0	$0	$591	$423,484	$13,085	$0	$0	$0	$4,730	$441,299
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lighting	59,040,843	0	0	3,255	0	0	4,987	$17,706,996	$4,780	$0	$0	$0	$1,512	$17,700,704	$214,764	$0	$0	$0	$2,094	$17,917,563
Military	1,358,941,142	1,477,747,188	1,477,747,188	56	1,920	3,086,866	57	$81,736,760	$703,496	($48,653)	($21,153)	$0	$5	$80,963,453	$384,703	($339,881)	($147,775)	$0	$88	$81,835,900
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LGS	1,358,939,222	1,477,746,388	1,477,746,388	50	0	3,086,866	57	$81,736,554	$702,745	($48,653)	($21,153)	$0	$5	$80,963,997	$384,698	($339,882)	($147,775)	$0	$88	$81,836,439
Lighting	1,920	800	800	6	1,920	0	0	$207	$751	$0	$0	$0	$0	-$544	$5	$0	$0	$0	$0	-$539
NC Retail	37,453,956,498	15,220,450,076	15,247,626,723	18,734,373	20,752,027,791	52,360,418	18,907,582	$3,647,001,864	$15,853,402	($793,706)	($350,689)	$0	$726,011	$3,629,278,056	$236,049,507	($3,464,685)	($1,518,627)	$0	$3,105,675	$3,873,416,550
	0	0	0	0	0	0		0	$0	0	0	0	0		0			0		
Rate Schedules (excludes REPS)																				
RES (includes RES-RECD)	15,868,304,518	0	0	15,140,463	15,868,304,518	0		$1,870,258,480	$9,512,395	$0	$0	$0	$457,213	$1,860,288,872	$138,838,867	$0	$0	$0		$1,999,127,739
SGS	1,833,796,271	485,409,069	485,699,616	1,979,357	1,833,796,271	0		$232,593,133	$784,793	($87,698)	($38,130)	$0	$194,441	$231,488,071	$17,240,669	($111,644)	($48,570)	$0		$248,888,954
MGS	2,591,152,591	848,679,847	850,323,349	205,345	0	13,469,393		$269,715,991	$1,007,358	($105,947)	($46,064)	$0	$20,794	$268,535,828	$17,496,955	($195,196)	($85,032)	$0		$286,313,011
SGS-TOU	7,945,092,948	4,696,071,246	4,746,807,709	259,738	0	20,693,572		$593,455,534	$916,650	($296,698)	($128,999)	$0	$25,150	$592,088,038	$18,583,666	($1,080,096)	($474,681)	$0		$612,226,481
LGS	928,891,890	971,119,429	976,689,277	1,085	0	2,326,941		$74,343,845	$70,164	($34,343)	($14,932)	$0	$206	$74,224,200	$759,553	($223,357)	($97,669)	$0		$75,304,779
LGS-TOU	1,807,333,210	3,743,504,191	3,712,128,402	1,609	0	3,631,757		$134,427,695	($80,953)	($277,625)	($120,706)	$0	$442	$134,109,875	$1,644,488	($861,006)	($371,213)	$0		$136,986,582
LGS-RTP	10,096,342	10,096,342	10,096,342	14	0	37,617		$983,644	$7,005	$0	$0	$0	$0	$976,639	$57,059	($2,322)	($1,010)	$0		$1,037,030
LGS-RTP-TOU	5,621,142,357	4,391,723,900	4,389,542,504	1,028	0	12,142,337		$321,514,715	$1,014,915	$0	$0	$0	$0	$320,499,800	$1,573,395	($1,010,096)	($438,954)	$0		$323,522,246
LGS Class	8,367,463,799	9,116,443,862	9,088,456,525	3,736	0	18,138,651		$531,269,898	$1,011,131	($311,968)	($135,638)	$0	$647	$529,810,514	$4,034,496	($2,096,782)	($908,846)	$0		$536,850,637
Rate Class																				
Residential	16,263,344,918	0	0	15,390,699	16,263,344,918	0	15,501,404	$1,910,802,434	$11,991,468	$0	$0	$0	$457,213	$1,898,353,752	$175,702,608	$0	$0	$0	$1,860,168	$2,075,916,528
SGS	1,888,523,635	490,060,750	497,052,093	2,095,919	1,829,501,043	0	2,122,533	$240,261,004	$807,984	($90,480)	($39,551)	$0	$206,079	$239,116,910	$17,739,588	($112,714)	($49,705)	$0	$898,968	$257,917,886
MGS	10,603,239,605	5,630,997,500	5,606,753,759	476,304	1,634,022,604	34,221,766	516,648	$870,655,610	$1,942,777	($404,137)	($175,500)	$0	$44,204	$868,088,993	$37,006,974	($1,295,129)	($560,675)	$0	$228,968	$907,180,740
LGS	8,367,463,799	9,038,344,111	9,082,463,805	3,736	752,815,527	18,138,651	14,515	$531,269,898	$1,011,131	($311,968)	($135,638)	$0	$3,285	$529,807,877	$4,034,496	($2,078,819)	($908,246)	$0	$20,350	$536,849,788
Lighting	331,384,542	61,047,715	61,357,066	767,715	272,343,699	0	752,482	$94,012,918	$100,042	$12,879	($0)	$0	$15,231	$93,910,524	$1,565,841	$21,977	$0	$0	$97,220	$95,551,608
	37,453,956,498	15,220,450,076	15,247,626,723	18,734,373	20,752,027,791	52,360,418	18,907,582	$3,647,001,864	$15,853,402	($793,706)	($350,689)	$0	$726,011	$3,629,278,056	$236,049,507	($3,464,685)	($1,518,627)	$0	$3,105,675	$3,873,416,550

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Actual MWH Sales by Jurisdiction - Subject to Weather
Twelve Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Harrington Workpaper 13

Line No.	Description	Reference	Retail North Carolina	Retail South Carolina	Total Retail	% NC	% SC
1	Residential	Company Records	16,328,636	2,059,298	18,387,934	88.80	11.20
2	Commercial	Company Records	11,694,307	1,595,073	13,289,379	88.00	12.00
3	Industrial	Company Records	7,795,150	2,226,975	10,022,124	77.78	22.22
4	Other Public Authority	Company Records	1,367,884	47,442	1,415,326	96.65	3.35
5	Total Retail Sales subject to weather	Sum 1 through 4	37,185,976	5,928,787	43,114,763		
6	Lighting	Company Records	55,689	11,361	67,051	83.06	16.94
7	Total Retail Sales	Line 5 + Line 6	37,241,666	5,940,149	43,181,814		

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2021 Production Plant Allocation Factors
Docket No. E-2, Sub 1292

Harrington Workpaper 14

2021 Total Production Plant	System	NC Retail	Residential	Small GS	Med GS	Lrg GS	Ltg
All - Production Plant	18,042,509	11,103,449	5,854,363	664,750	2,833,356	1,750,980	-
NC Retail % to Total System		61.54%	32.45%	3.68%	15.70%	9.70%	0.00%
Allocation of Classes to Total NC Retail		100.00%	52.73%	5.99%	25.52%	15.77%	0.00%

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Scenario Differences
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Exhibit 2 Schedule 1: Line Loss

Line Losses & Company Use	Exh 2 Sch 1 Pg 1 Ln 16	(2,364,858)
Generation	Exh 2 Sch 1 Pg 1 Ln 10	59,115,406
	%	-4.000%
	Multiplier	1.040004

Schedule 2: Proposed Nuclear Capacity Factor & Normalized Sales

Normalized Sales	Exh 4, Total Co., Ln 4	61,545,696
Projected Billing Period Sales	Exh 2 Sch 1 Pg 1 Ln 18	61,541,989
Difference		3,707
Gross up for losses	Difference x Multiplier	3,855
	MWh changes in Coal	3,855
	MWH changes in Losses	(148)

	Before Adj	Adj	Total
Total Coal MWh	9,087,592	3,855	9,091,447
Total Losses MWh	(2,364,858)	(148)	(2,365,007)
	6,722,734	3,707	6,726,440

	Before Adj	After Adj	Adjustment
Total Coal $	$ 351,295,882	$ 351,444,903	$ 149,021

Schedule 3: NERC 5 year average Capacity Factor & Projected Sales

		Nuclear-MWHs	Nuclear Costs
Nuclear	WP 1	29,601,651	$ 176,202,941
Nuclear - NERC Average	WP 2	29,426,308	$ 175,159,216
	Adjustment	(175,343)	$ (1,043,725)

		Coal-MWH	Coal Costs	
Coal MWh	WP 3, WP4	9,087,592	$ 351,295,882	
Adjustment from Above	Adjustment above	175,343	$ 6,778,182	(Priced at the avg Coal $/MWH)
		9,262,935	$ 358,074,064	

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Projected Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Workpaper 16

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 325,973,737	$ 27,391,213	$ 353,364,950
2	Amount in 2021 Filing: Docket E-2 Sub 1272	277,781,551	22,812,629	300,594,180
3	Reduction in prior year docket in excess of 2.5%	-		-
4	Increase/(Decrease)	$ 48,192,186	$ 4,578,585	$ 52,770,771
5	2.5% of 2021 NC revenue of $3,522,552,951			88,063,824
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases from Dispatchable Units	$ 88,434,734	62.74%	$ 55,483,952
WP 4	Purchases for REPS Compliance Energy	116,315,118	62.74%	72,976,105
WP 4	Purchases for REPS Compliance Capacity	23,896,105	61.54%	14,705,781
WP 4	Purchases from Qualifying Facilities Energy	224,803,592	62.74%	141,041,773
WP 4	Purchases from Qualifying Facilities Capacity	46,050,571	61.54%	28,339,750
WP 4	Allocated Economic Purchases	21,400,024	62.74%	13,426,375
	Total	$ 520,900,144		$ 325,973,737

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Dispatchable Purchased Energy	$ 46,946,023	62.22%	$ 29,209,815
Prior Year	Purchases for REPS Compliance Energy	114,179,542	62.22%	71,042,511
Prior Year	Purchases for REPS Compliance Capacity	23,408,207	60.86%	14,247,300
Prior Year	Purchases from Qualifying Facilities Energy	212,217,851	62.22%	132,041,947
Prior Year	Purchases from Qualifying Facilities Capacity	43,472,451	60.86%	26,459,312
Prior Year	Allocated Economic Purchases	7,683,487	62.22%	4,780,666
Prior Year	Total	$ 447,907,561		$ 277,781,551

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Normalized Sales
Billing Period December 1, 2022 - November 30, 2023
Docket No. E-2, Sub 1292

Harrington Workpaper 17

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 319,420,641	$ 27,391,213	$ 346,811,854
2	Amount in 2021 Filing: Docket E-2 Sub 1272	275,034,750	22,812,629	297,847,378
3	Reduction in prior year docket in excess of 2.5%	-		-
4	Increase/(Decrease)	$ 44,385,891	$ 4,578,585	$ 48,964,476
5	2.5% of 2021 NC revenue of $3,522,552,951			88,063,824
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases from Dispatchable Units	$ 88,434,734	61.29%	$ 54,198,850
WP 4	Purchases for REPS Compliance	116,315,118	61.29%	71,285,855
WP 4	Purchases for REPS Compliance Capacity	23,896,105	61.54%	14,705,781
WP 4	Purchases from Qualifying Facilities Energy	224,803,592	61.29%	137,775,007
WP 4	Purchases from Qualifying Facilities Capacity	46,050,571	61.54%	28,339,750
WP 4	Allocated Economic Purchases	21,400,024	61.29%	13,115,397
	Total	$ 520,900,144		$ 319,420,641

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Dispatchable Purchased Energy	$ 46,946,023	61.50%	$ 28,871,384
Prior Year	Purchases for REPS Compliance Energy	114,179,542	61.50%	70,219,397
Prior Year	Purchases for REPS Compliance Capacity	23,408,207	60.86%	14,247,300
Prior Year	Purchases from Qualifying Facilities Energy	212,217,851	61.50%	130,512,081
Prior Year	Purchases from Qualifying Facilities Capacity	43,472,451	60.86%	26,459,312
Prior Year	Allocated Economic Purchases	7,683,487	61.50%	4,725,276
Prior Year	Total	$ 447,907,561		$ 275,034,750

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test-Detail Calculation
Nine Months Ended March 31, 2022
Docket No. E-2, Sub 1292

Harrington Workpaper 18

Line No.		Reference	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	* Dec-21	** Jan-22	Feb-22	Mar-22	9ME
1	Adjusted System kWh Sales, at generation		6,187,516,297	6,319,231,299	5,831,904,879	4,720,480,675	3,513,392,593	4,672,933,727	5,824,633,525	6,252,061,869	5,074,629,090	48,396,783,954
2	NC Retail kWh Sales, at generation		3,777,188,636	3,770,171,053	3,804,571,871	3,008,985,840	1,847,658,788	2,900,227,616	3,415,752,880	4,196,740,403	3,255,389,979	29,976,687,066
3	NC Retail % of Sales	Line 2 / Line 1	61.05%	59.66%	65.24%	63.74%	52.59%	62.06%	58.64%	67.13%	64.15%	61.94%
	Applicable Purchase Power, Excl. JDA											
4	System Purchase Power, Excl. JDA		$ 42,679,929	$ 47,310,113	$ 37,190,128	$ 36,451,856	$ 31,192,486	$ 31,841,268	$ 30,623,091	$ 30,012,193	$ 31,211,498	$ 318,512,561
5	NC Purchase Power	Line 4 * Line 3	$ 26,054,096	$ 28,226,094	$ 24,261,801	$ 23,235,583	$ 16,403,823	$ 19,762,087	$ 17,958,368	$ 20,145,895	$ 20,022,271	$ 197,284,832
6	NC Retail kWh Sales, at delivery		3,640,178,832	3,632,757,561	3,666,084,042	2,900,680,335	1,777,446,003	2,791,497,250	3,292,881,233	4,045,880,376	3,137,475,127	28,884,880,758
7	NC Incurred Rate	Line 5 / Line 6 * 100	0.716	0.777	0.662	0.801	0.923	0.708	0.545	0.498	0.638	0.683
	Capacity											
8	System Capacity		$ 16,306,802	$ 10,600,439	$ 11,315,723	$ 8,504,904	$ (431,230)	$ 4,366,691	$ 3,321,058	$ 4,777,238	$ 4,978,082	$ 63,739,707
9	NC Capacity (@ Production Plant%)	60.865%	$ 9,925,062	$ 6,451,910	$ 6,887,264	$ 5,176,472	$ (262,466)	$ 2,657,767	$ 2,021,347	$ 2,907,644	$ 3,029,887	$ 38,794,886
10	NC Incurred Rate	Line 9/Line 6*100	0.273	0.178	0.188	0.178	(0.015)	0.095	0.061	0.072	0.097	0.134
11	Total NC Incurred Rate	Line 7 + Line 10	0.988	0.955	0.850	0.979	0.908	0.803	0.607	0.570	0.735	0.817
12	Billed Rate	Billed Rates Below	0.715	0.715	0.715	0.715	0.715	0.719	0.723	0.723	0.723	
13	(Over)/Under cents per kwh	Line 131- Line 12	0.273	0.239	0.135	0.264	0.193	0.085	(0.116)	(0.153)	0.012	
14	(Over)/Under $	Line 6 * Line 13 /100	$ 9,946,435	$ 8,698,354	$ 4,931,081	$ 7,667,851	$ 3,429,960	$ 2,360,305	$ (3,823,113)	$ (6,192,372)	$ 372,713	$ 27,391,213

Billed Rate from Docket E-2, Sub 1250 - Jul'21-Nov'21

15	Purchases from Dispatchable Units & Economic Purchases	49,904,833	2020 Harrington WP4
16	Total MWH Sales	61,484,301	2020 Harrington WP3
17	Billed Rate for Purchases	**0.081**	
18	Renewables (energy)	131,543,318	2020 Harrington WP4
19	Total MWH Sales	61,484,301	2020 Harrington WP3
20	Billed Rate for Renewables	**0.214**	
21	QF Purchases (energy)	191,949,817	2020 Harrington WP4
22	Total MWH Sales	61,484,301	2020 Harrington WP3
23	Billed Rate for Renewables	**0.312**	
24	Capacity (REPS and QF)	66,306,741	2020 Harrington WP4
25	Total MWH Sales	61,484,301	2020 Harrington WP3
26	Billed Rate for Capacity	**0.108**	
27	Total Billed Rate	**0.715**	To Line 12

*** December billed rate is based on prorated billing factors**

	Prior Bill Rate (Sub 1250)	New Bill Rate (Sub 1272)	December Blended Rate	
Approved Rates	0.715	0.723		
Ratios of Days to rate	55.30%	44.70%		
Prorated Rate	**0.395**	**0.323**	**0.719**	To Line 12

**** January billed rate is based on prorated billing factors**

	Prior Bill Rate (Sub 1250)	New Bill Rate (Sub 1272)	January Blended Rate	
Approved Rates	0.715	0.723		
Ratios of Days to rate	0.0%	100.0%		
Prorated Rate	**(0.000)**	**0.723**	**0.723**	To Line 12

Billed Rate from Docket E-2, Sub 1272 - Feb'22-Mar'22

Purchases from Dispatchable Units & Economic Purchases	54,629,510	2021 Revised Harrington WP4
Total MWH Sales	61,963,546	2021 Revised Harrington WP3
Billed Rate for Purchases	**0.088**	
Renewables (energy)	114,179,542	2021 Revised Harrington WP4
Total MWH Sales	61,963,546	2021 Revised Harrington WP3
Billed Rate for Renewables	**0.184**	
QF Purchases (energy)	212,217,851	2021 Revised Harrington WP4
Total MWH Sales	61,963,546	2021 Revised Harrington WP3
Billed Rate for Renewables	**0.342**	
Capacity (REPS and QF)	66,880,658	2021 Revised Harrington WP4
Total MWH Sales	61,963,546	2021 Revised Harrington WP3
Billed Rate for Capacity	**0.108**	
Total Billed Rate	**0.723**	To Line 12

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**MATTHEW L. CAMERON FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew L. Cameron and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Lead Engineer for procurement of natural uranium for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" or the "Company").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEP?

A. I am responsible for natural uranium procurement for the nuclear units owned and operated by DEP. I have the same responsibility for DEC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Purdue University with a Bachelor of Science degree in Nuclear Engineering and from Wake Forest University with a Master's degree in Business Administration. I began my career with the Company in 2006 as an engineer and worked in Duke Energy's safety analysis group where I performed plant response and accident analysis. I assumed my current role having the lead for purchasing uranium and conversion services in 2012.

I became a registered professional engineer in the state of North Carolina in 2011.

Q. HAVE YOU FILED TESTIMONY OR TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDING?

A. No.

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

A. The purpose of my testimony is to (1) provide information regarding DEP's nuclear fuel purchasing practices, (2) provide costs for the April 1, 2021 through March 31, 2022 test period ("test period"), and (3) describe changes forthcoming for the December 1, 2022 through November 30, 2023 billing period ("billing period").

Q. YOUR TESTIMONY INCLUDES TWO EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Cameron Exhibit 1, which is a Graphical Representation of the Nuclear Fuel Cycle, and Cameron Exhibit 2, which sets forth the Company's Nuclear Fuel Procurement Practices.

Q. PLEASE DESCRIBE THE PROCESSES USED TO DEVELOP NUCLEAR FUEL.

A. In order to prepare uranium for use in a nuclear reactor, it must be processed from an ore to a ceramic fuel pellet. This process is commonly broken into four distinct industrial stages: (1) mining and milling; (2) conversion; (3) enrichment; and (4) fabrication. This process is illustrated graphically in Cameron Exhibit 1.

Uranium is often mined by either surface (*i.e.*, open cut) or underground mining techniques, depending on the depth of the ore deposit. The ore is then sent to a mill where it is crushed and ground-up before the uranium is extracted by leaching, the process in which either a strong acid or alkaline solution is used to dissolve the uranium. Once dried, the uranium oxide ("U_3O_8") concentrate – often referred to as yellowcake – is packed in drums for transport to a conversion facility. Alternatively, uranium may be mined by in situ leach ("ISL") in which oxygenated groundwater is circulated through a very porous ore body to dissolve the uranium and bring it to the surface. ISL may also use slightly acidic or alkaline solutions to keep the uranium in solution. The uranium is then recovered from the solution in a mill to produce U_3O_8.

After milling, the U_3O_8 must be chemically converted into uranium hexafluoride ("UF_6"). This intermediate stage is known as conversion and produces the feedstock required in the isotopic separation process.

Naturally occurring uranium primarily consists of two isotopes, 0.7% Uranium-235 ("U-235") and 99.3% Uranium-238. Most of this country's nuclear reactors (including those of the Company) require U-235 concentrations in the 3-5% range to operate a complete cycle of 18 to 24 months between refueling outages. The process of increasing the concentration of U-235 is known as enrichment. Gas centrifuge is the primary technology used by the commercial enrichment suppliers. This process first applies heat to the UF_6 to create a gas. Then, using the mass differences between the uranium isotopes, the natural uranium is separated into two gas streams, one being enriched to the desired level of U-235, known as low enriched uranium, and the other being depleted in U-235, known as tails.

Once the UF_6 is enriched to the desired level, it is converted to uranium dioxide powder and formed into pellets. This process and subsequent steps of inserting the fuel pellets into fuel rods and bundling the rods into fuel assemblies for use in nuclear reactors is referred to as fabrication.

Q. PLEASE PROVIDE A SUMMARY OF DEP'S NUCLEAR FUEL PROCUREMENT PRACTICES.

A. As set forth in Cameron Exhibit 2, DEP's nuclear fuel procurement practices involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments.

For uranium concentrates, conversion, and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. Throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEP's exposure to price volatility. Diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Q. PLEASE DESCRIBE DEP'S DELIVERED COST OF NUCLEAR FUEL DURING THE TEST PERIOD.

A. Staggering long-term contracts over time for each of the components of the nuclear fuel cycle means DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets. DEP mitigates the impact of market volatility on the portfolio of supply contracts by using a mixture of pricing mechanisms. Consistent with its portfolio approach to contracting, DEP entered into several long-term contracts during the test period.

DEP's portfolio of diversified contract pricing yielded an average unit cost of $40.35 per pound for uranium concentrates during the test period, representing a 7% decrease from the prior test period.

A majority of DEP's enrichment purchases during the test period were delivered under long-term contracts negotiated prior to the test period. The staggered portfolio approach has the effect of smoothing out DEP's exposure to price volatility. The average unit cost of DEP's purchases of enrichment services during the test period increased 43% to $143.99 per Separative Work Unit.

Delivered costs for fabrication and conversion services have a limited impact on the overall fuel expense rate because the dollar amounts for these purchases represent a substantially smaller percentage – 18% and 5%, respectively, for the fuel batches recently loaded into DEP's reactors – of DEP's total direct fuel cost relative to uranium concentrates or enrichment, which are

39% and 38%, respectively.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN NUCLEAR FUEL MARKET CONDITIONS.

A. Prices in the uranium concentrate markets have increased due to production cutbacks and activity from financial investors. Industry consultants believe that recent production cutbacks have been warranted due to the previously existing oversupply conditions and that market prices need to further increase in the longer term to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements.

Market prices for conversion and enrichment services have recently increased primarily due to the potential for supply deficits as a result of the Russian invasion of Ukraine.

Fabrication is not a service for which prices are published; however, industry consultants expect fabrication prices will continue to generally trend upward.

Q. WHAT CHANGES DO YOU SEE IN DEP'S NUCLEAR FUEL COST IN THE BILLING PERIOD?

A. Because fuel is typically expensed over two to three operating cycles (roughly three to six years), DEP's nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period, as well as prior periods. The fuel residing in the reactors during the billing period will have been obtained under historical contracts negotiated in various market conditions. Each of these contracts contributes to a portion of the uranium, conversion, enrichment, and fabrication costs reflected in the total fuel expense.

The average fuel expense is expected to remain relatively flat, from 0.5915 cents per kWh incurred in the review period, to approximately 0.5952 cents per kWh in the billing period.

Q. WHAT STEPS IS DEP TAKING TO PROVIDE STABILITY IN ITS NUCLEAR FUEL COSTS AND TO MITIGATE PRICE INCREASES IN THE VARIOUS COMPONENTS OF NUCLEAR FUEL?

A. As discussed earlier and as described in Cameron Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEP relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating a range of pricing mechanisms, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEP's exposure to price volatility.

Although costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a cents per kWh basis will likely continue to be a fraction of the cents per kWh cost of fossil fuel. Therefore, customers will continue to benefit from DEP's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

E-2, Sub 1292

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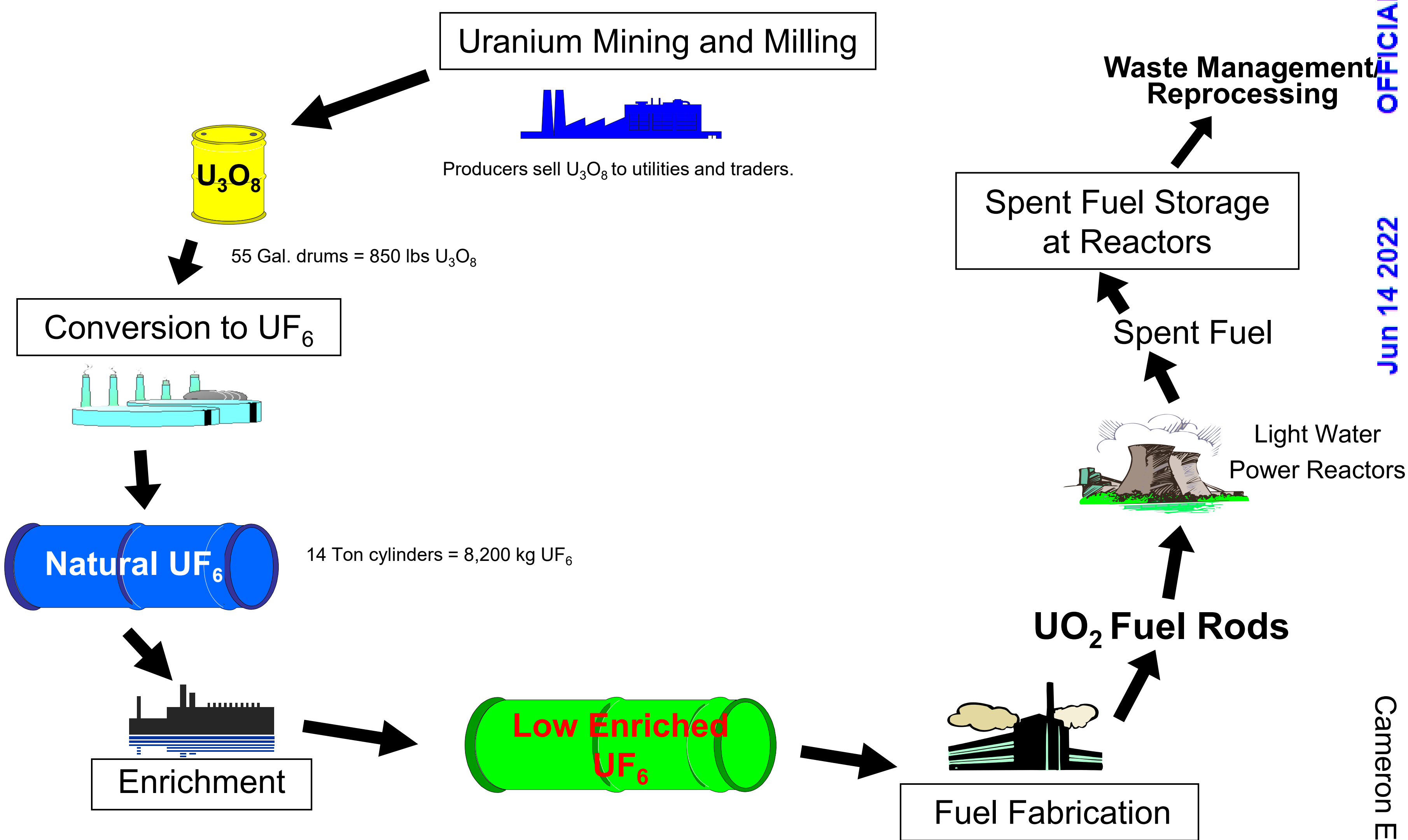
Jun 14 2022

The Nuclear Fuel Cycle



Cameron Exhibit 1

Duke Energy Progress, LLC Nuclear Fuel Procurement Practices

The Company's nuclear fuel procurement practices are summarized below:

- Near and long-term consumption forecasts are computed based on factors such as: nuclear system operational projections given fleet outage/maintenance schedules, adequate fuel cycle design margins to key safety licensing limitations, and economic tradeoffs between required volumes of uranium and enrichment necessary to produce the required volume of enriched uranium.
- Nuclear system inventory targets are determined and designed to provide: reliability, insulation from market volatility, and sensitivity to evolving market conditions. Inventories are monitored on an ongoing basis.
- On an ongoing basis, existing purchase commitments are compared with consumption and inventory requirements to ascertain additional needs.
- Qualified suppliers are invited to make proposals to satisfy additional or future contract needs.
- Contracts are awarded based on the most attractive evaluated offer, considering factors such as price, reliability, flexibility and supply source diversification/portfolio security of supply.
- For uranium concentrates, conversion and enrichment services, long term supply contracts are relied upon to fulfill the largest portion of forward requirements. By staggering long-term contracts over time, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Due to the technical complexities of changing suppliers, fabrication services are generally sourced to a single domestic supplier on a plant-by-plant basis using multi-year contracts.
- Spot market opportunities are evaluated from time to time to supplement long-term contract supplies as appropriate based on comparison to other supply options.
- Delivered volumes of nuclear fuel products and services are monitored against contract commitments. The quality and volume of deliveries are confirmed by the delivery facility to which the Company has instructed delivery. Payments for such delivered volumes are made after the Company's receipt of such delivery facility confirmations.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**TOM RAY FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Tom Ray, and my business address is 12700 Hagers Ferry Road, Huntersville, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy") with direct executive accountability for Duke Energy's North Carolina nuclear stations, including Duke Energy Progress, LLC's ("DEP" or the "Company") Brunswick Nuclear Station ("Brunswick") in Brunswick County, North Carolina, the Harris Nuclear Station ("Harris") in Wake County, North Carolina, and Duke Energy Carolinas, LLC's ("DEC") McGuire Nuclear Station, located in Mecklenburg County, North Carolina.

Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT OF NUCLEAR OPERATIONS?

A. As Senior Vice President of Nuclear Operations, I am responsible for providing oversight for the safe and reliable operation of Duke Energy's nuclear stations in North Carolina. I am also involved in the operations of Duke Energy's other nuclear stations, including DEP's Robinson Nuclear Station ("Robinson") located in Darlington County, South Carolina.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in nuclear engineering from North Carolina State University and received a senior reactor operator certification from Duke Energy's McGuire Nuclear Station ("McGuire"). My career in the nuclear power industry spans over 30 years. I began my nuclear career as an engineer with the Bechtel Power Corporation where I was field engineer assigned to projects at various nuclear plants. In 1989, I joined Duke Energy as a nuclear engineer in the corporate headquarters. I transferred to reactor engineering at the McGuire Nuclear Station in 1994, and progressed through leadership roles at McGuire in engineering, maintenance, and outage management. In 2004, I joined the Catawba Nuclear Station team as safety assurance manager, and was named maintenance manager in 2005 and engineering manager in 2009. I was transferred to Oconee Nuclear Station as engineering manager in 2010 and was promoted to plant manager in 2012 and vice president of the Oconee Station in 2016. I was named site vice president for McGuire in 2017 and held that position until February 2022 when I assumed my current role.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. No.

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

A. The purpose of my testimony is to describe the performance of the Brunswick, Harris, and Robinson nuclear plants during the period of April 1, 2021 through March 31, 2022 (the "test period"). I will provide information regarding scheduled refueling outages and discuss the nuclear capacity factor being proposed by the Company in determining the fuel factor to be reflected in customer rates during the billing period of December 1, 2022 through November 30, 2023 ("billing period").

Q. PLEASE DESCRIBE RAY EXHIBIT 1 INCLUDED WITH YOUR TESTIMONY.

A. Ray Exhibit 1 is a confidential exhibit outlining the planned schedule for refueling outages for DEP's nuclear units for the period of April 1, 2022 through November 30, 2023. This exhibit represents DEP's current plan, which is subject to adjustment due to changes in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEP'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 3,593[1] megawatts ("MWs") of generating capacity, made up as follows:

Brunswick -	1,870 MWs
Harris -	964 MWs
Robinson -	759 MWs

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF DEP'S NUCLEAR GENERATION ASSETS.

A. The Company's nuclear fleet consists of three generating stations and a total of four units. Brunswick is a boiling water reactor facility with two units and was the first nuclear plant built in North Carolina. Unit 2 began commercial operation in 1975, followed by Unit 1 in 1977. The operating licenses for Brunswick were renewed in 2006 by the NRC, extending operations up to 2036 and 2034 for Units 1 and 2, respectively. Harris is a single unit pressurized water reactor that began commercial operation in 1987. The NRC issued a renewed license for Harris in 2008, extending operation up to 2046. Robinson is also a single unit pressurized water reactor that

[1] As of January 1, 2022.

began commercial operation in 1971. The license renewal for Robinson Unit 2 was issued by the NRC in 2004, extending operation up to 2030.

Q. WERE THERE ANY CAPACITY CHANGES WITHIN DEP'S NUCLEAR PORTFOLIO DURING THE TEST PERIOD?

A. No.

Q. WHAT ARE DEP'S OBJECTIVES IN THE OPERATION OF ITS NUCLEAR GENERATION ASSETS?

A. The primary objective of DEP's nuclear generation department is to safely provide reliable and cost-effective electricity to DEP's customers in North and South Carolina. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees receive extensive, comprehensive training and execute their responsibilities to the highest standards in accordance with detailed procedures that are continually updated to ensure best practices. The Company maintains station equipment and systems reliably and ensures timely implementation of work plans and projects that enhance the performance of systems, equipment, and personnel. Station refueling and maintenance outages are conducted through the execution of well-planned, well-executed, and high-quality work activities, which ensure that the plant is prepared for operation until the next planned outage.

Q. PLEASE DISCUSS THE PERFORMANCE OF DEP'S NUCLEAR FLEET DURING THE TEST PERIOD.

A. The Company operated its nuclear stations in a reasonable and prudent manner during the test period, providing approximately 49.2% of the total power generated by DEP.

The four nuclear units operated at an actual system average capacity factor of 93.99% during the test period, which included two refueling outages. During 2021, DEP's nuclear plants established a new net generation record.

The performance results discussed in my testimony demonstrate DEP's continued commitment to achieving high performance without compromising safety and reliability.

Q. HOW DOES THE PERFORMANCE OF DEP'S NUCLEAR FLEET COMPARE TO INDUSTRY AVERAGES?

A. The Company's nuclear fleet has a history of strong operational performance that has historically exceeded industry averages. Industry averages were developed utilizing the North American Electric Reliability Council's ("NERC") Generating Unit Statistical Brochure ("NERC Brochure"), which is considered by the North Carolina Utilities Commission in Rule R8-55(k) in establishing fuel factors in proceedings such as this. The most recently published NERC Brochure indicates an industry average capacity factor of 93.49% for comparable units for the five-year period of 2016 through 2020. The Company's test period capacity factor of 93.99%, and 2-year average[2] capacity factor of 93.77% both exceeded the industry five-year average.

Q. WHAT IMPACTS A UNIT'S AVAILABILITY AND WHAT IS DEP'S PHILOSOPHY FOR SCHEDULING REFUELING AND MAINTENANCE OUTAGES?

A. In general, refueling requirements, maintenance requirements, prudent maintenance practices, and NRC operating requirements impact the availability of DEP's nuclear

[2] This represents the simple average for the current test period and prior test period of 12 months ended March 2021 for the DEP nuclear fleet.

system. Prior to a planned outage, DEP develops a detailed schedule for the outage including major tasks to be performed along with sub-schedules for particular activities.

The Company's scheduling philosophy is to plan for a best possible outcome for each outage activity within the outage plan. For example, if the "best ever" time a particular outage task was performed is 10 days, then 10 days or less becomes the goal for that task in each subsequent outage. Those individual goals are incorporated into an overall outage schedule. The Company aggressively works to meet that schedule, and measures itself against that objective. Further, to minimize potential impacts to outage schedules, "discovery activities" (walk-downs, inspections, etc.) are scheduled at the earliest opportunities so that any maintenance or repairs identified through those activities can be promptly incorporated into the outage plan. Those discovery activities also have pre-planned contingency actions to ensure that, when incorporated into the schedule, the activities required for appropriate repair can be performed as efficiently as possible.

As noted, the Company uses the schedule for measuring outage planning and execution and driving continuous improvement efforts. However, in order to provide reasonable, rather than best ever, total outage time for planning purposes, particularly with the dispatch and system operating center functions, DEP also develops an allocation of outage time, which incorporates reasonable schedule losses. The development of each outage allocation is dependent on maintenance and repair activities included in the outage, as well as major projects to be implemented during the outage. Both schedule and allocation are set to drive continuous improvement in outage planning and execution.

Q. HOW DOES DEP HANDLE OUTAGE EXTENSIONS AND FORCED OUTAGES?

A. When an outage extension becomes necessary, DEP seeks to ensure that work completed in the extension results in longer continuous run times and fewer forced outages, thereby reducing fuel costs in the long run. Therefore, if an unanticipated issue that has the potential to become an on-line reliability issue is discovered while a unit is off-line for a scheduled outage and repair cannot be completed within the planned work window, the outage is usually extended to perform necessary maintenance or repairs prior to returning the unit to service. In the event that a unit is forced off-line, every effort is made to safely perform the repair and return the unit to service as quickly as possible.

Q. DOES DEP PERFORM POST-OUTAGE CRITIQUES AND CAUSE ANALYSES FOR INTERNAL IMPROVEMENT EFFORTS?

A. Yes. DEP applies self-critical analysis to each outage using the benefit of hindsight. This includes identifying every potential cause of an outage delay or event resulting in a forced or extended outage, and applies lessons learned to drive continuous improvement. The Company also evaluates the performance of each function and discipline involved in outage planning and execution in order to identify areas in which it can utilize a self-critical analysis to drive further improvement efforts.

Q. ARE SUCH ANALYSES INTENDED TO ASSESS OR MAKE A DETERMINATION REGARDING THE PRUDENCE OR REASONABLENESS OF A PARTICULAR ACTION OR DECISION?

A. No. Given this focus on identifying opportunities for improvement, these critiques and cause analyses are not intended to document the broader context of the outage nor do they make any attempt to assess whether the actions taken were reasonable in light of what was known at the time of the events in question. Instead, the reports utilize hindsight (*e.g.*, subsequent developments or information not known at the time) to identify every potential cause of the incident in question. However, such a review is quite different from evaluating whether the actions or decisions in question were reasonable given the circumstances that existed at that time.

Q. WHAT REFUELING OUTAGES WERE COMPLETED AT DEP'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. There were two refueling outages[3] completed during the test period: Harris in the spring of 2021 followed by Brunswick Unit 1 during the spring of 2022.

Harris was disconnected from the grid for refueling on April 24, 2021. Maintenance activities, safety and reliability enhancements, and testing and inspections were completed as the unit was refueled. Electrical maintenance performed during the outage included winding penetrations repairs to the unit auxiliary and start-up transformers, refurbishment of 2 vital inverters, and 1A battery replacement. Nuclear instrumentation detector and cable replacements, and turbine control system maintenance was completed during the outage. Reliability

[3] The Brunswick Unit 2 spring 2021 refueling outage (B2R25) began on 3/5/2021 and ended on 4/5/2021; 4 days into this test period. The outage was reviewed in the 2021 fuel proceeding.

enhancements also included stem replacement and inspection of the 'C' main steam isolation valve. Sections of circulating water pre-stressed concrete cylinder pipe were inspected, and a carbon fiber wrap was installed on portions to extend the longevity and address reliability concerns that could threaten unit operations. These inspections and any needed repairs will continue over several future refueling outages. Condenser hardening work which included inspection and tube plugging was completed on the circulating water west waterbox and cooling tower blowdown lines were inspected. The refueling outage was successfully completed with no recordable injuries, no human performance deficiencies and under budget. After refueling, maintenance, and testing and inspections were completed, the unit returned to service on May 14, 2021. The outage duration was 20.4 days compared to a scheduled allocation of 25 days. This represented the shortest refueling outage in the unit's history and was also accomplished with the lowest dose recorded for a Harris refueling outage.

Q **PLEASE DESCRIBE THE REFUELING OUTAGE PERFORMED AT BRUNSWICK UNIT 1.**

A. The Brunswick Unit 1 spring 2022 refueling outage began on March 4, 2022. In addition to refueling, maintenance activities, safety and reliability enhancements, and testing and inspections were completed. Reliability enhancing maintenance activities completed during the outage included replacement of the 1A and 2A reactor recirculation pump seals, 2 reactor water clean-up primary containment isolation valves, and 4 safety relief valve main body assemblies. The Company also replaced the unit's startup auxiliary transformer (SAT), which had been in service since the unit began commercial operation in 1977 and had reached the end of its expected life. The

SAT replacement improves the reliability of the unit. A modification replacing the unit's manual no load disconnect switch with an electronically operated circuit breaker was completed during the outage. The same modification was completed on Unit 2 during the spring 2021 refueling outage, and this modification increases the operability margin and improves reliability of the protection device. A portion of the Unit 1 buried service water piping had a carbon fiber reinforced polymer lining installed to address pipe degradation and ensure continued reliability of the both the nuclear service water and conventional service water systems for the remaining life of the plant. The remaining portions of the site's service water buried pipe will be addressed in future refueling outages. To ensure reliability of the unit's fuel, ultrasonic cleaning of fuel assemblies and reactor bottom head foreign material search and retrieval activities were completed. Prior to restart from the outage, inspections were completed on the 1B reactor feedpump steam path, west moisture separator reheater internals, and the conventional service water header. The outage was successfully completed with no personnel injuries, human performance clock resets, nor reportable environmental events. The unit returned to service on April 4, 2022[4]; a duration of 30.65 days compared to a scheduled allocation of 33 days.

Q. WHAT OTHER OUTAGES OCCURRED DURING THE TEST PERIOD?

A. In May 2021, Brunswick Unit 1 was offline for 12 days to replace reactor recirculation pump seals. Shortly after Harris exited the spring refueling outage in May 2021, and while at approximately 30% power, the generator was disconnected from the grid for 13 hours due to a vibrating bracket on the main generator ground detection system.

[4] The refueling outage ended on 4/4/2022; 3.7 days beyond the current test period.

In June of 2021, Harris entered a 3-day planned maintenance outage to repair an oil leak on the unit auxiliary transformer. Robinson began a 15-day outage in October 2021 to replace a reactor coolant pump seal. In December 2021, the Brunswick Unit 1 generator was disconnected from the grid for 25 hours to repair the no load disconnect switch and Brunswick Unit 2 was offline for 6.6 days beginning in late January 2022 to repair inleakage in the main condenser and drywell leaks. Plant personnel responded appropriately to these challenges and safely and efficiently returned the units to service.

Q. WHAT CAPACITY FACTOR DOES DEP PROPOSE TO USE IN DETERMINING THE FUEL FACTOR FOR THE BILLING PERIOD?

A. The Company proposes to use a 94.05% capacity factor, which is a reasonable value for use in this proceeding based upon the operational history of DEP's nuclear units and the number of planned outage days scheduled during the billing period. This proposed percentage is reflected in the testimony and exhibits of Company witness Harrington and exceeds the five-year industry weighted average capacity factor of 93.49% for comparable units as reported in the NERC Brochure during the period of 2016 to 2020.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)
Application of Duke Energy Progress, LLC	)
R8-55 Relating to Fuel and Fuel-Related	)
Charge Adjustments for Electric Utilities	)

TOM RAY CONFIDENTIAL EXHIBIT 1

FILED UNDER SEAL

JUNE 14, 2022

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**JOHN A. VERDERAME FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John A. Verderame. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Vice President, Fuels & Systems Optimization for Duke Energy Corporation ("Duke Energy"). In that capacity, I lead the organization responsible for the purchase and delivery of coal, natural gas, fuel oil, and reagents to Duke Energy's regulated generation fleet, including Duke Energy Progress, LLC ("Duke Energy Progress," "DEP," or the "Company") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Companies"). In addition, I manage the fleet's power trading, system optimization, energy supply analytics, and contract administration functions.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics from the University of Rochester in 1983, and a Master's in Business Administration in Finance from Rutgers University in 1985. I have worked in the energy industry for 20 years. Prior to that, from 1986 to 2001, I was a Vice President in the United States (US) Government Bond Trading Groups at the Chase Manhattan Bank and Cantor Fitzgerald. My responsibilities as a US Government Securities Trader included acting as the Firm's market maker in US Government Treasury securities. I joined Progress Energy, in 2001, as a Real-Time Energy Trader. My responsibilities as a Real-Time Energy Trader included managing the real-time energy position of the Progress Energy regulated utilities. In 2005, I was promoted to Manager of the Power Trading group. My role as manager included responsibility for the short-term capacity and energy position of the Progress Energy regulated utilities in the Carolinas and Florida.

In 2012, upon consummation of the merger between Duke Energy Corp. and Progress Energy, Progress Energy became Duke Energy Progress and I was named Managing Director, Trading and Dispatch. As Managing Director, Trading and Dispatch I was responsible for Power and Natural Gas Trading and Generation Dispatch on behalf of Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I assumed my current position in November 2019.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDING?

A. Yes. I testified in support of DEP's 2020 fuel and fuel-related cost recovery application in Docket No. E-2, Sub 1272 and DEC's 2021 fuel and fuel-related cost recovery application in Docket No. E-7, Sub 1263.

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

A. The purpose of my testimony is to describe DEP's fossil fuel purchasing practices, provide actual fossil fuel costs for the period April 1, 2021 through March 31, 2022 ("test period") versus the period April 1, 2020 through March 31, 2021 ("prior test period"), and describe changes projected for the billing period of December 1, 2022 through November 30, 2023 ("billing period").

Q. YOUR TESTIMONY INCLUDES FOUR EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND

UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Verderame Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Verderame Exhibit 2, which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases for the test period and prior test period, and CONFIDENTIAL Verderame Exhibit 3, which summarizes the fuels related transactional activity between DEC and Piedmont Natural Gas Company, Inc. ("Piedmont") for spot commodity transactions during the test period, as required by the Merger Agreement between Duke Energy and Piedmont, of which DEP receives an allocated portion based on its pro rata share of the overall gas plant burns for the respective month. Lastly, Verderame Exhibit 4, shows the calculation of the average forward NYMEX Henry Hub price for the billing period.

Q. PLEASE PROVIDE A SUMMARY OF DEP'S FOSSIL FUEL PROCUREMENT PRACTICES.

A. A summary of DEP's fossil fuel procurement practices is set out in Verderame Exhibit 1.

Q. PLEASE DESCRIBE THE COMPANY'S APPROACH TO UNIT COMMITMENT AND DISPATCH OF ITS GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS.

A. Both DEP and DEC perform the same detailed daily process to determine the unit commitment plan that economically and reliably meets the Company's projected system needs over the next seven days. The Company utilizes a production cost model to determine an optimal unit commitment plan to economically and reliably meet system requirements. The model minimizes the production costs needed to serve the projected customer demand within reliability and other system constraints over a period of time. Inputs to the model include, but are not limited to, the following: (1) forecasted customer energy demand; (2) the latest forecasted fuel prices, reflective of market supply chain dynamics; (3) variable transportation rates; (4) planned maintenance and refueling outages at the generating units; (5) generating unit performance parameters; (6) reliability constraints such as units run to maintain day-ahead planning reserves or units required to run for transmission or voltage support; and (7) expected market conditions associated with power purchases and off-system sales opportunities. The production cost model output produces the optimized hourly unit commitment plan for the 7-day forecast period. This unit commitment plan also provides the starting point for dispatch, but dispatch is then also subject to real time adjustments due to changing system conditions including management of natural gas transportation constraints. The unit commitment plan is prepared daily and adjusted, as needed, throughout any given day to respond to changing real time system conditions.

Q. PLEASE DESCRIBE THE COMPANY'S DELIVERED COST OF COAL AND NATURAL GAS DURING THE TEST PERIOD.

A. The Company's average delivered cost of coal per ton for the test period was $84.26 per ton, compared to $92.52 per ton in the prior test period, representing a decrease of approximately 9%. The cost of delivered coal includes an average transportation cost of $35.15 per ton in the test period, compared to $36.75 per ton in the prior test period, representing a decrease of approximately 4%. The Company's average price of gas purchased for the test period was $5.44 per

Million British Thermal Units ("MMBtu"), compared to $3.76 per MMBtu in the prior test period, representing an increase of approximately 44%. The cost of gas is inclusive of gas supply, transportation, storage, and financial hedging.

DEP's coal burn for the test period was 2.9 million tons, compared to a coal burn of 3.4 million tons in the prior test period, representing a decrease of 16%. The Company's natural gas burn for the test period was 174.6 million MBtu, compared to a gas burn of 157.5 million MBtu in the prior test period, representing an increase of approximately 11%.

Changes in coal and natural gas burns were primarily driven by increased demand from the economic rebound experienced following the COVID-19 shutdowns in 2020. Gas to coal generation switching was limited by lower natural gas prices early in the test period and rapidly escalating coal commodity prices in the latter half of 2021 and early 2022 which off-set increasing natural gas prices over the same period.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN COAL AND NATURAL GAS MARKET CONDITIONS.

A. Coal markets continue to be distressed, and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers following the past several years of steep declines in coal generation demand, which has impacted the ability of producers to respond to changes in demand during 2021 and early 2022; (2) natural gas price volatility; (3) renewed uncertainty from the new administration regarding proposed and imposed U.S. Environmental Protection Agency regulations for power plants; (4) increased demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening access to investor financing, coupled with deteriorating credit quality is increasing the overall costs of financing for coal producers; (7) continued shifts in production from thermal to metallurgical coal as producers move away from supplying declining electric generation to take advantage of increasing demand from industry; and (8) increasing labor and resource constraints due to structural changes in the coal industry further limiting suppliers' operational flexibility. In addition, the coal supply chain experienced increasing challenges throughout 2021 and early 2022 as historically low utility stockpiles—combined with rapidly increasing demand for coal, both domestically and internationally—made procuring additional coal supply increasingly challenging. Producers were unable to respond to this rapid rise in demand due to capacity constraints resulting from labor and resource shortages. These factors combined to drive both domestic and export coal prices in 2021 and early 2022 to record levels. Going into summer 2022, coal commodity costs remain at historically high levels as higher natural gas prices and strong domestic and foreign demand continue to put pressure on coal supplies.

Declining demand for coal in the utility sector has also driven rail transportation providers to modify their business models to be less dependent on coal related transportation revenues. Although rail transportation providers are required to provide rail service, the Company's rail transportation providers have limited resources to adapt to significant changes in scheduling demand resulting from the Company's burn volatility, specifically in higher than forecasted coal burn scenarios. In 2021 and early 2022, the Company experienced increased delivery delays created by rail transportation labor and resource shortages. At this time, the Company expects rail transportation labor and resource constraints to continue into 2023.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years as producers enhanced production techniques, enhanced efficiencies, and lowered production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in 2021 and early 2022, such dynamics were influenced primarily by growth in export demand, stable production, lower than average storage inventory balances, and seasonal weather demand. Lack of gas production response to rising prices and the uncertainty of future coal deliveries has placed continued stress on gas storage replenishment keeping upward pressure on gas prices in the near term. There is a growing need for natural gas pipeline infrastructure, as gas production particularly in low cost regions such as Appalachia is constrained as pipeline infrastructure permitting and regulatory process approval efforts are increasingly challenged delaying planned pipeline construction and commissioning timing.

Over the longer term planning horizon, natural gas supply has the ability to respond to changing demand while the pipeline infrastructure needed to move the growing supply to meet demand related to power generation, liquefied natural gas exports, and pipeline exports to Mexico is highly uncertain.

Q. WHAT ARE THE PROJECTED COAL AND NATURAL GAS CONSUMPTIONS AND COSTS FOR THE BILLING PERIOD?

A. Based on the most recently completed forecast for use in this filing which used market prices as of April 13, 2022, DEP's projected coal burn for the billing period is 3.5 million tons, compared to 2.9 million tons consumed during the test period.

DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $100.18 per ton for the billing period compared to $84.26 per ton in the test period. This increase in delivered costs is primarily driven by increased coal commodity costs due to limited coal supply and increased domestic and international demand. This includes an average projected total transportation cost of $31.55 per ton for the billing period, compared to $35.13 per ton in the test period. This projected delivered cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of Central Appalachian coal DEP is able to purchase and deliver and the non-Central Appalachian coal DEP is able to consume; (3) changes in transportation rates; (4) performance of contract deliveries by suppliers and railroads which may not occur despite the Company's strong contract compliance monitoring process; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

DEP's natural gas burn projection for the billing period is approximately 140.5 million MBtu, compared to the 174.6 million MBtu consumed during the test period. The average forward Henry Hub price for the billing period is $5.51 per MMBtu, compared to $4.41 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

Q. WHAT STEPS IS DEP TAKING TO ENSURE A COST-EFFECTIVE RELIABLE FUEL SUPPLY?

A. The Company continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost effective manner. With respect to coal procurement, the Company's procurement strategy includes: (1) having an appropriate mix of term contract and spot purchases for coal; (2) staggering coal contract expirations in order to limit exposure to forward market price changes; and (3) diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels. Additionally, the Company negotiates coal transportation contracts that support secure, reliable deliveries in a lower coal burn environment. In July 2022, the Company will implement the Commission accepted Fuel Management Agreement between DEP and DEC allowing DEC to be the commercial face to the market for coal, reagents and related transportation in the Carolinas. This agreement provides for an increasingly flexible fuel procurement strategy along with increased real-time logistical flexibility resulting in operational and cost efficiencies for customers.

The Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply. These procurement practices include contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption. DEP continues to maintain a short-term natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach. DEP continues to monitor and make adjustments as necessary to its natural gas hedging program.

Lastly, the Company procures long-term firm interstate and intrastate transportation to provide natural gas to its generating facilities. Given the Company's limited amount of contracted firm interstate transportation, the Company purchases shorter term firm interstate pipeline capacity as available from the capacity release market. The Company's firm transportation ("FT") provides the underlying framework for the Company to manage the natural gas supply needed for reliable and cost-effective generation. First, it allows the Company access to lower cost natural gas supply from Transco Zone 3 and Zone 4 and the ability to transport gas to Zone 5 for delivery to the Carolinas' generation fleet. Second, the Company's FT allows it to manage intraday supply adjustments on the pipeline through injections or withdrawals of natural gas supply from storage, including on weekends and holidays when the gas markets are closed. Third, it allows the Company to mitigate imbalance penalties associated with Transco pipeline restrictions, which can be significant. The Company's customers receive the benefit of each of these aspects of the Company's FT: access to lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Duke Energy Progress, LLC Fossil Fuel Procurement Practices

Coal

- Using Stochastic cost production modeling, near and long-term coal consumption is forecasted based on inputs such as load projections, weather, fleet maintenance and availability schedules, coal quality and cost, non-coal commodity and emission prices, environmental permit and emissions constraints, projected renewable energy production, and wholesale energy imports and exports.
- Station and system inventory targets are developed to provide generational reliability, insulation from short-term market volatility, and adaptability to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to determine changes in supply needs.
- All qualified suppliers are invited to participate in Request for Proposals to satisfy additional supply needs.
- Spot market solicitations are conducted on an on-going basis to supplement existing purchase commitments.
- Contracts are awarded based on the highest customer value, considering factors such as price, quality, transportation, reliability and flexibility.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on certified scale weights and coal quality analysis meeting ASTM standards as established by ASTM International.

Gas

- Using Stochastic cost production modeling, near and long-term natural gas consumption is forecasted based on inputs such as load projections, weather, commodity and emission prices, projected renewable energy production, and fleet maintenance and availability schedules.
- Physical procurement targets are developed to procure a cost effective and reliable natural gas supply.
- Natural gas supply is contracted utilizing a portfolio of long term, short term, spot market and physical call option agreements
- Short-term and long-term Requests for Proposals and market solicitations are conducted with potential suppliers, as needed, to procure the cost competitive, secure, and reliable natural gas supply, firm transportation, and storage capacity needed to meet forecasted gas usage.
- Short-term and spot purchases are conducted on an on-going basis to supplement term natural gas supply.
- On a continuous basis, existing purchases are compared against forecasted gas usage to determine changes in supply and transportation needs.
- Natural gas transportation for the generation fleet is obtained through a mix of long-term firm transportation agreements, and shorter-term pipeline capacity purchases.

- A targeted percentage of the natural gas fuel price exposure is managed via a rolling 60-month structured financial natural gas hedging program.
- Through the Asset Management and Delivered Supply Agreement between Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC implemented on January 1, 2103, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for the combined Carolinas gas fleet.

Fuel Oil

- No. 2 fuel oil is burned primarily for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All No. 2 fuel oil is moved via pipeline to applicable terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, the Company relies on a combination of inventory, responsive suppliers with access to multiple terminals, and trucking agreements to manage its needs. Replenishment of No. 2 fuel oil inventories at the applicable plant facilities is done on an "as needed basis" and coordinated between fuel procurement and station personnel.
- Formal solicitations for supply may be conducted as needed with an emphasis on maintaining a network of reliable suppliers at a competitive market price in the region of our generating assets.

DUKE ENERGY PROGRESS
Summary of Coal Purchases
Twelve Months Ended March 2022 & 2021
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
1	April 2021	159,723	36,359	196,082
2	May	98,095	0	98,095
3	June	147,937	0	147,937
4	July	169,614	24,638	194,252
5	August	73,921	168,609	242,530
6	September	133,922	121,974	255,896
7	October	122,146	86,378	208,524
8	November	136,575	148,046	284,621
9	December	48,856	208,029	256,885
10	January 2022	61,357	158,119	219,476
11	February	168,791	83,853	252,644
12	March	252,259	35,831	288,090
13	**Total** (Sum L1:L12)	**1,573,196**	**1,071,836**	**2,645,032**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
14	April 2020	205,573	(6,844)	198,729
15	May	37,639	(11,647)	25,992
16	June	13,060	(5,985)	7,075
17	July	205,293	(1,250)	204,043
18	August	280,431	0	280,431
19	September	292,974	0	292,974
20	October	281,434	12,427	293,861
21	November	244,691	24,851	269,542
22	December	293,006	0	293,006
23	January 2021	147,303	74,534	221,837
24	February	195,798	49,231	245,029
25	March	221,728	49,040	270,768
26	**Total** (Sum L14:L25)	**2,418,930**	**184,357**	**2,603,287**

DUKE ENERGY PROGRESS
Summary of Gas Purchases
Twelve Months Ended March 2022 & 2021
MBTUs

Line No.	Month	MBTUs
1	April 2021	9,833,075
2	May	10,394,016
3	June	14,427,637
4	July	16,994,787
5	August	16,866,819
6	September	13,052,405
7	October	12,424,350
8	November	14,950,650
9	December	15,166,665
10	January 2022	17,956,480
11	February	16,578,138
12	March	15,924,389
13	**Total** (Sum L1:L12)	**174,569,411**

Line No.	Month	MBTUs
14	April 2020	8,048,333
15	May	10,825,017
16	June	13,181,648
17	July	17,709,068
18	August	15,791,691
19	September	12,396,157
20	October	11,455,652
21	November	11,887,528
22	December	17,038,827
23	January 2021	15,211,307
24	February	12,301,205
25	March	11,672,834
26	**Total** (Sum L14:L25)	**157,519,267**

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)
Application of Duke Energy Progress, LLC	)
R8-55 Relating to Fuel and Fuel-Related	)
Charge Adjustments for Electric Utilities	)

JOHN A. VERDERAME CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

JUNE 14, 2022

Duke Energy Progress, LLC

Average Forward NYMEX Henry Hub Price
for Billing Period December 1, 2022 through November 30, 2023
as of COB 4/13/22

Month	NYMEX HH
Dec-22	$ 7.414
Jan-23	$ 7.516
Feb-23	$ 7.307
Mar-23	$ 6.511
Apr-23	$ 4.755
May-23	$ 4.585
Jun-23	$ 4.617
Jul-23	$ 4.656
Aug-23	$ 4.665
Sep-23	$ 4.650
Oct-23	$ 4.683
Nov-23	$ 4.787
Average	**$ 5.512**

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress,	)	**DIRECT TESTIMONY OF**
LLC Pursuant to G.S. 62-133.2 and	)	**BRYAN P. WALSH FOR**
NCUC Rule R8-55 Relating to Fuel	)	**DUKE ENERGY PROGRESS,**
and Fuel-Related Charge Adjustments	)	**LLC**
for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bryan P. Walsh. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President of Central Operational Services and Oversight for Duke Energy Business Services, LLC ("DEBS"). DEBS is a service company subsidiary of Duke Energy Corporation ("Duke Energy") that provides services to Duke Energy and its subsidiaries, including Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" or the "Company").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from The Catholic University of America with a Bachelor of Mechanical Engineering degree. I also graduated from the Georgia Institute of Technology with a Master of Science in Mechanical Engineering. I am a registered Professional Engineer in the State of North Carolina. My career began with Duke Energy as part of Duke / Fluor Daniel in 1999 as an associate engineer assisting in the design and commissioning of new combined-cycle power plants. I transferred to Duke Power in 2003 and worked in the Technical Services group for Fossil-Hydro. Since that time, I have held various roles of increasing responsibility in the generation engineering, operations areas, and project management, including the role of technical manager at DEC's Marshall Steam Station, and also station manager at Duke Energy Indiana's Gallagher Station & Markland Hydro Station. I was also the Midwest Regional Manager from 2012 to 2015, with overall responsibility for the

Midwest Gas Turbine Fleet and various coal-fired facilities in Indiana and Kentucky. During my time in the Midwest, I also served as Chairman of the Indiana Energy Association's Power Production Committee, which brought together Duke Energy and peer utilities Vectren, NIPSCO, AEP and IP&L for operational experience exchanges, along with coordination on common industry issues. I was named General Manager for Outages & Projects in the Carolinas in 2015. Next, I became the General Manager of Fossil-Hydro Organizational Effectiveness in 2017. I assumed my current role in 2019.

Q. WHAT ARE YOUR DUTIES AS VICE PRESIDENT OF CENTRAL OPERATIONAL SERVICES AND OVERSIGHT?

A. In this role, I am responsible for providing engineering, environmental compliance planning, technical services, and maintenance services, for Duke Energy's fleet of fossil, hydroelectric, and solar (collectively, "Fossil/Hydro/Solar") facilities.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before the North Carolina Utilities Commission on behalf of the Company in its Duke Energy Progress fuel case in Docket No. E-2, Sub 1272.

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

A. The purpose of my testimony is to (1) describe DEP's Fossil/Hydro/Solar generation portfolio and changes made since the 2021 fuel cost recovery proceeding, as well as those expected in the near term; (2) discuss the performance of DEP's Fossil/Hydro/Solar facilities during the period of April 1, 2021 through March 31, 2022 (the "review period"); (3) provide information on significant

Fossil/Hydro/Solar outages that occurred during the review period; and (4) provide information concerning environmental compliance efforts.

Q. PLEASE DESCRIBE DEP'S FOSSIL/HYDRO/SOLAR GENERATION PORTFOLIO FOR THE REVIEW PERIOD.

A. The Company's Fossil/Hydro/Solar generation portfolio consists of 8,868 MWs of generating capacity, made up as follows:

Coal-fired -	3,143 MWs
Combustion Turbines -	2,408 MWs
Combined Cycle Turbines -	3,054 MWs
Hydro -	228 MWs
Solar -	35 MWs[1]

The 3,143 MWs of coal-fired generation represent two generating stations and a total of five units. These units are equipped with emission control equipment, including selective catalytic reduction ("SCR") equipment for removing nitrogen oxides ("NOx"), flue gas desulfurization ("scrubber") equipment for removing sulfur dioxide ("SO_2"), and low NOx burners. This inventory of coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content – providing flexibility for DEP to procure the most cost-effective options for fuel supply.

The Company has a total of 24 simple cycle combustion turbine ("CT")

[1] This value represents the relative dependable capacity contribution to meeting summer peak demand, based on the Company's integrated resource planning metrics. The nameplate capacity of the Company's solar facilities is 141MWs.

units, the larger 14 of which provide 2,148 MWs, or 89% of CT capacity. These 14 units are located at the Asheville, Darlington, Richmond County (Smith Energy Complex), and Wayne County (H.F. Lee) facilities, and are equipped with water injection and/or low NOx burners for NOx control. The 3,054 MWs shown as "Combined Cycle Turbines" ("CC") represent six power blocks. The two Asheville Combined Cycle power blocks have a configuration of one CT and one steam turbine. The H.F. Lee Energy Complex CC power block has a configuration of three CTs and one steam turbine. The two Richmond County power blocks located at the Smith Energy Complex consist of two CTs and one steam turbine each. The Sutton Combined Cycle at Sutton Energy Complex consists of two CTs and one steam turbine. The six CC power blocks are equipped with SCR equipment, and all eleven CTs have NOx controls. The steam turbines do not combust fuel and, therefore, do not require NOx controls. The Company's hydro fleet consists of 15 units providing 228 MWs of capacity. The Company's solar fleet consists of four sites providing 35 MWs of capacity.

Q. DID ANY NOTABLE CHANGES OCCUR WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEP'S 2021 ANNUAL FUEL PROCEEDING?

A. No, there were none.

Q. WHAT ARE DEP'S OBJECTIVES IN THE OPERATION OF ITS FOSSIL/ HYDRO/ SOLAR FACILITIES?

A. The primary objective of DEP's Fossil/Hydro/Solar generation department is to provide safe, reliable, and cost-effective electricity to DEP's customers. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with procedures, guidelines, and a standard operating model. Like safety, environmental compliance is a "first principle," and DEP works very hard to achieve high level results.

The Company achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power options for DEP's customers. Equipment inspection and maintenance outages are generally scheduled during the spring and fall months when customer demand is reduced due to milder temperatures. These outages are well-planned and executed with the primary purpose of preparing the unit for reliable operation until the next planned outage.

Q. HOW MUCH GENERATION DID EACH TYPE OF GENERATING FACILITY PROVIDE FOR THE REVIEW PERIOD?

A. For the review period, DEP's total system generation was 60,167,889 megawatt-hours ("MWHs"), of which 30,586,287 MWHs, or approximately 51%, was provided by the Fossil/Hydro/Solar fleet. The breakdown includes a 38% contribution from gas facilities, 11% contribution from coal-fired stations, 1% contribution from hydro sources, and 0.4% from solar facilities.

Q. HOW DID DEP COST EFFECTIVELY DISPATCH THE DIVERSE MIX OF GENERATING UNITS DURING THE REVIEW PERIOD?

A. The Company's portfolio includes a diverse mix of units that, along with its nuclear capacity, allows DEP to meet the dynamics of customer load requirements in a logical and cost-effective manner. The addition of new CC units within the Carolinas' portfolio in recent years has provided DEP with additional natural gas resources that feature state-of-the-art technology for increased efficiency and significantly reduced emissions. DEP also uses the Joint Dispatch Agreement with DEC, which allows generating resources for DEP and DEC to be dispatched as a single system to enhance dispatching the lowest cost resources available. The cost and operational characteristics of each unit generally determine the type of customer load situation (e.g., base and peak load requirements) that a unit would be called upon or dispatched to support.

Q. WHAT WAS THE HEAT RATE FOR DEP'S COAL-FIRED AND COMBINED CYCLE UNITS DURING THE REVIEW PERIOD?

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the review period, the Company's five coal units produced 21% of the Fossil/Hydro/Solar generation, with the average heat rate for the coal-fired units being 11,290 Btu/kWh. The most active station during this period was Roxboro, providing 84% of the coal production for the fleet with an average heat rate of 11,018 Btu/kWh. During the review period, the Company's six combined cycle power blocks produced 70% of the Fossil/Hydro/Solar generation, with an average heat rate of 7,182 Btu/kWh.

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DEP'S FOSSIL/ HYDRO/SOLAR FLEET DURING THE REVIEW PERIOD.

A. The Company's generating units operated efficiently and reliably during the review period. Several key measures are used to evaluate the operational performance depending on the generator type: (1) equivalent availability factor ("EAF"), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned maintenance (i.e., forced) outage time); (2) net capacity factor ("NCF"), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF is affected by the dispatch of the unit to serve customer needs); (3) starting reliability ("SR"), which represents the percentage of successful starts; and (4) equivalent forced outage factor ("EFOF") – which quantifies the number of period hours in a year during which the unit is unavailable because of forced outages and forced deratings.

The following chart provides operational results categorized by generator type, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Unit Statistical Brochure representing the period 2016 through 2020. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating.

Generator Type	Measure	Review Period	2016-2020	Nbr of Units
		DEP Operational Results	NERC Average	
Coal Fired Test Period	EAF	63.1%	79.8%	183
	NCF	23.0%	53.2%	
	EFOF	8.1%	n/a	
Coal Fired Summer Peak	EAF	78.2%	n/a	n/a
Total CC Average	EAF	81.0%	84.9%	345
	NCF	67.6%	54.3%	
	EFOF	0.7%	n/a	
Total CT Average	EAF	83.8%	86.6%	709
	SR	99.2%	98.5%	
Hydro	EAF	78.5%	79.4%	1059
Solar	NCF	20.8%	n/a	n/a

Q. PLEASE DISCUSS SIGNIFICANT OUTAGES OCCURRING AT DEP'S FOSSIL/HYDRO/SOLAR FACILITIES DURING THE REVIEW PERIOD.

A. In general, planned maintenance outages for all fossil and hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most units had at least one short, planned outage during this review period to inspect and maintain plant equipment.

In the fall, Richmond County CT Unit 1 held an outage to perform advanced gas path ("AGP") upgrades and exhaust frame replacement. Richmond County CC PB4 had an outage to perform gas turbine inspections, cooling tower upper half rebuild, steam turbine valve inspection/repairs, and BOP safety valve inspection/repairs. Roxboro Unit 4 had an outage to perform precipitator repairs, and perform an inspection on the air heater. Roxboro Unit 1 had an outage to replace burners, batteries, and perform maintenance air heater outlet expansion joint. Mayo Unit 1 had an outage to replace absorber agitators, perform inspection of the absorber tower, and conduct back-end duct repairs. Roxboro Unit 3 had an outage to perform selective catalytic reduction ("SCR") screen replacement, high energy pipe ("HEP") inspections, and absorber agitator replacement. Roxboro Unit 2 had an outage to complete primary air fan replacement and HEP inspections.

In the spring, Roxboro Unit 4 performed an outage to complete an economizer hopper replacement, rebuild stop valves, a boiler inspection, and Mercury and Air Toxics Standards ("MATS") inspection. Sutton CC had an outage to perform a borescope inspection, drain valve replacements, generator inspections, boiler feed water pump replacement, and CT transition expansion joint replacement. H.F. Lee CC had an outage to perform a hot gas path inspection ("HGPI")on the gas turbines, steam turbine valve maintenance and inspections, and minor Balance of Plant ("BOP") maintenance.

Q. HOW DOES DEP ENSURE EMISSIONS REDUCTIONS FOR ENVIRONMENTAL COMPLIANCE?

A. The Company has installed pollution control equipment on coal-fired units, as well as new generation resources, to meet various current federal, state, and local reduction requirements for NOx and SO2 emissions. The SCR technology that DEP currently operates on the coal-fired units uses ammonia or urea for NOx removal and the scrubber technology employed uses crushed limestone or lime for SO2 removal. SCR equipment is also an integral part of the design of the newer CC facilities in which aqueous ammonia (19% solution of NH_3) is introduced for NOx removal.

Overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emissions reduction required. The Company is managing the impacts, favorable or unfavorable, because of changes to the fuel mix and/or changes in coal burn and utilization of non-traditional coals. Overall, the goal is to effectively comply with emissions regulations and provide the optimal total-cost solution for operation of the unit. The Company will continue to leverage new technologies and chemicals to meet both present and future state and federal emissions requirements including the MATS rule. MATS chemicals that DEP may use in the future to reduce emissions include, but may not be limited to, activated carbon, mercury oxidation chemicals, and mercury re-emission prevention chemicals. Company witness Harrington provides the cost information for DEP's chemical use and forecast.

Q. DOES THAT CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress , LLC	)	**DIRECT TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF DAVID B. JOHNSON FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David B. Johnson. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Corporation ("Duke Energy") as Director of Business Development and Compliance.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. My educational background includes a Bachelor of Science in Civil Engineering from the University of Tennessee. With respect to professional experience, I have been in the utility industry for over 38 years. I started as an associate Design Engineer in the Design Engineering Department at Duke Power in 1980. From 1991-1995, I worked for Duke Energy's affiliate companies Duke/Fluor Daniel and Duke Engineering & Services, Inc. In 1996, I worked in the initial Duke Power Trading Group in Charlotte, North Carolina, where I focused on marketing and business development and management until 2006. From 2006 to 2017, I worked as a Business Development Manager and Director in the Duke Energy wholesale and renewable energy areas. I began my current role in late 2017.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY.

A. I am responsible for wholesale Power Purchase Agreements ("PPA") that Duke Energy enters into with third party suppliers. These include PPAs that Duke

Energy Carolinas, LLC ("DEC") and Duke Energy Progress ("DEP") enter into with Qualifying Facilities ("QFs"), renewable PPAs to comply with North Carolina's Renewable Energy Efficiency Portfolio ("REPS") standard, Competitive Procurement of Renewable Energy ("CPRE") PPAs, and conventional (non-renewable) PPAs. I have responsibility for the negotiation and execution of these PPAs, as well as the on-going management of all executed PPAs. In addition, I am responsible for Duke Energy's compliance with the REPS and the CPRE Program.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I provided testimony in the 2018 Avoided Cost proceeding (NCUC Docket No. E-100, Sub 158) for DEC and DEP. I also recently provided testimony in the DEC fuel rider proceeding (DOCKET NO. E-7, SUB 1263).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present information and data required by the NCUC in accordance with the "Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations (Docket No. E-100, Sub 101 and E-100, Sub 158 – dated August 17, 2021). In this Order, the Commission directed DEC and DEP, in future fuel and fuel-related charge adjustment proceedings conducted pursuant to N.C. Gen. Stat. 62-133.2, to address the SISC avoidance process in their prefiled direct testimony, identify the specific facility(ies) and amount of SISC avoided in supporting exhibits and work papers, and the results of any audits performed on QFs seeking to avoid the SISC.

Q. DO YOU HAVE ANY INFORMATION TO REPORT AT THIS TIME?

A. No. There are currently no operating solar QF facilities at this time that contain energy storage systems. There are also currently no executed PPAs that contain SISC (sub 158 and later) that also include an energy storage system.

There were two (2) solar facility bids in Tranche 1 of CPRE that contained energy storage. However, these PPAs did not include SISC and, therefore, did not include an option for the QF to avoid the SISC.

Duke will continue to monitor future solar QF PPAs with SISC and energy storage that provide notice to Duke that they intend to avoid some or all of the SISC. Duke will provide any data on the ability of these future QF facilities to avoid the SISC in future fuel proceedings for DEC and DEP.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.