Jack E. Jirak
Deputy General Counsel

Mailing Address:
NCRH 20 / P.O. Box 1551
Raleigh, NC 27602

o: 919.546.3257
f: 919.546.2694

jack.jirak@duke-energy.com

June 15, 2021

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell, 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 1272**

Dear Ms. Campbell:

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 testimony, exhibits, and workpapers of Dana M. Harrington, and the testimony and exhibits of Kenneth D. Church, John A. Verderame, Ben Waldrep, and Bryan P. Walsh containing the information required in NCUC Rule R8-55.

Certain information contained in the exhibits of Mr. Verderame and Mr. Waldrep 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.

Please contact me if you have any questions.

Respectfully submitted,

Jack E. Jirak

Enclosures
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 1272, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 15th day of June, 2021.

Jack E. Jirak
Deputy General Counsel
Duke Energy Corporation
P.O. Box 1551/NCRH 20
Raleigh, North Carolina 27602
(919) 546-3257
Jack.jirak@duke-energy.com

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

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:

Jack E. Jirak
Deputy General Counsel
Duke Energy Corporation
Post Office Box 1551/NCRH 20
Raleigh, North Carolina 27602
(919) 546-3257
Jack.jirak@duke-energy.com

Dwight W. Allen
Allen Law Offices, PLLC
4030 Wake Forest Rd., Suite 115

Raleigh, NC 27609
Tel: (919) 838-0529
dallen@theallenlawoffices.com

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, 2020 – March 31, 2021 ("test period").

4. In Docket No. E-2, Sub 1250, 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	2.080¢ per kWh
Small General Service	2.126¢ per kWh
Medium General Service	2.228¢ per kWh
Large General Service	2.204¢ per kWh
Lighting	1.392¢ per kWh

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

Residential	2.129¢ per kWh
Small General Service	2.062¢ per kWh
Medium General Service	2.133¢ per kWh
Large General Service	2.070¢ per kWh
Lighting	1.481¢ per kWh

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

Residential	0.121¢ per kWh
Small General Service	0.102¢ per kWh
Medium General Service	0.184¢ per kWh
Large General Service	0.396¢ per kWh
Lighting	0.270¢ per kWh

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

Residential	2.250¢ per kWh
Small General Service	2.164¢ per kWh
Medium General Service	2.317¢ per kWh
Large General Service	2.466¢ per kWh
Lighting	1.751¢ per kWh

The new fuel factors should become effective for service on or after December 1, 2021.

6. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Kenneth D. Church, John A. Verderame, Ben Waldrep, 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 93.18% using projected billing period sales, and based on the proposed nuclear capacity factor of 93.21% using normalized test period sales. These base fuel and fuel-related costs factors are:

	NERC Average	Normalized Sales
Residential	2.311¢ per kWh	2.245¢ per kWh
Small General Service	2.231¢ per kWh	2.161¢ per kWh
Medium General Service	2.361¢ per kWh	2.313¢ per kWh
Large General Service	2.497¢ per kWh	2.462¢ per kWh
Lighting	1.886¢ per kWh	1.735¢ 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	2.250¢ per kWh
Small General Service	2.164¢ per kWh
Medium General Service	2.317¢ per kWh
Large General Service	2.466¢ per kWh
Lighting	1.751¢ per kWh

Respectfully submitted this 15th day of June, 2021.

By: ______________________________

Jack E. Jirak
Deputy General Counsel
Duke Energy Corporation
Post Office Box 1551/NCRH 20
Raleigh, North Carolina 27602
Tel: (919) 546-3257
Jack.jirak@duke-energy.com

Dwight W. Allen
Allen Law Offices, PLLC
4030 Wake Forest Rd., Suite 115
Raleigh, NC 27609
Tel: (919) 838-0529
dallen@theallenlawoffices.com

ATTORNEYS FOR DUKE ENERGY PROGRESS, LLC

VERIFICATION

STATE OF NORTH CAROLINA)
) DOCKET NO. E-2, SUB 1272
COUNTY OF MECKLENBURG)

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

That she is Rates 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: 6-10-2021

Peggy Holton
Official Signature of Notary

Peggy Holton, Notary Public
Notary's printed or typed name

PEGGY HOLTON NOTARY (Official Seal) PUBLIC WAKE COUNTY, NC

My commission expires: 12/22/2021

I signed this notarial certificate on 6-10-21 according to the emergency video notarization requirements contained in G.S. 10B-25.

Notary Public location during video notarization: Wake County

Stated physical location of principal during video notarization: Mecklenburg County

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

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 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am a Rates 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 for two years.

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 fuel proceeding under Docket No. E-2, Sub 1250.

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, 2020 through March 31, 2021 ("test period"), and the billing period is December 1, 2021 through November 30, 2022 ("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 93.21% proposed nuclear capacity factor and projected billing period megawatt hour ("MWh")

sales.

- Exhibit 2, Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 93.21% proposed nuclear capacity factor and normalized test period MWh sales.
- Exhibit 2, Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting an 93.18% 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 2021 Monthly Fuel Report, as required by NCUC Rule R8-52.
- Exhibit 6, Report 2: March 2021 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 93.21% nuclear capacity factor as testified to by Company witness Waldrep. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Harrington Exhibit 1 in cents per kWh ("cents/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	2.129	2.062	2.133	2.070	1.481
EMF Increment/(Decrement)	0.121	0.102	0.184	0.396	0.270
Proposed Net Fuel and Fuel-Related Costs Factors	2.250	2.164	2.317	2.466	1.751

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 a decrease of 0.1%, 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	2.250	2.164	2.317	2.466	1.751
Approved Net Fuel and Fuel-Related Costs Factors	2.260	2.175	2.324	2.471	1.773

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 93.21%, as explained in Company witness Waldrep'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 93.21% 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 93.18%. This capacity factor is based on the 2015 through 2019 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 2020 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 an 93.18% NERC nuclear capacity factor compared to the proposed 93.21% 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, with consideration given to any fuel and fuel-related costs or benefits that should be directly assigned. Costs are further allocated among customer classes using the uniform percentage average bill adjustment methodology in this fuel proceeding as adopted in DEP's 2020 fuel and fuel-related cost recovery proceeding under Docket No. E-2, Sub 1250.

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 2020 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 decrease of 0.1% was calculated by dividing the fuel and fuel-related cost decrease of $3 million for the North Carolina retail jurisdiction by the normalized annual North Carolina retail revenues at the existing rates of $3.4 billion. The cost decrease of $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 decrease in fuel rate per kWh by projected North Carolina retail kWh sales for the billing period. 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 decrease for each customer class is applied to current annual revenues by customer class to determine a revenue decrease for each customer class. The revenue decrease is divided by the projected billing period sales for each class to derive a cents/kWh decrease. The current total fuel and fuel-related cost factors for each class are adjusted by the proposed cents/kWh decrease 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 2020, 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 2020.

Q. HARRINGTON EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD (OVER)/UNDER RECOVERY BALANCE AND THE PROPOSED EMF RATE. 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 $71.2 million for the combined customer classes of the North Carolina retail jurisdiction.

The test period (over)/under collection was determined each month by comparing the actual fuel revenues collected from each class to actual fuel and fuel-related costs incurred by class based on the actual monthly sales of each class. DEP System fuel and fuel-related costs incurred were first allocated to the North Carolina retail jurisdiction based on jurisdictional sales, with consideration given to any fuel and fuel-related costs or benefits that should be directly assigned. The North Carolina retail amount of purchased power capacity costs from renewables and qualifying facilities were allocated among customer classes based on production plant allocators from DEP's 2020 cost of service study. All other 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.

Lastly, due to the timing of receipt of rider orders in the prior year annual fuel rider proceeding, the Commission approved DEP's request to implement Docket E-2, Sub 1250 rates as of December 7, 2020, to continue billing customers under Docket E-2, Sub 1204 rates for the period of December 1, 2020 through December 6, 2020, and to true up the differences as part of DEP's 2021 rider proceedings. As agreed, DEP has reflected the appropriate true up balances in the EMF component of this filing.

Q. IS THE COMPANY PROPOSING ANY COST ADJUSTMENTS TO THE TWELVE-MONTH TEST PERIOD UNDER-COLLECTION OF FUEL AND FUEL-RELATED COSTS AS REPORTED ON THE MONTHLY FUEL REPORTS?

A. Yes. 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 $(1.5) million and $5.3 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 $5.3 million has also been included in projected billing period costs consistent with the approach approved by the Commission in Docket E-2, Sub 1250.

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 2.444 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, and Company witness Church discusses nuclear fuel costs and nuclear fuel procurement strategies. Company witness Waldrep discusses the performance of DEP's nuclear generation fleet. The Company's test year capacity factor of 93.55% exceeded the NERC five-year average of 93.18%. Witness Waldrep 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. The largest contributor to the decrease in the proposed fuel and fuel-related cost factors is an increase in generation supplied by lower priced natural gas compared to other fuel sources.

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, 2021
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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 1250)						
1	Approved Fuel and Fuel-Related Costs Factors	Input	2.080	2.126	2.228	2.204	1.392
2	EMF Increment / (Decrement)	Input	0.180	0.049	0.096	0.267	0.381
3	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
4	Approved Net Fuel and Fuel-Related Costs Factors	Sum	2.260	2.175	2.324	2.471	1.773
	Other Fuel and Fuel-Related Cost Factors						
5	NERC Capacity Factor of 93.18% with Projected Billing Period MWh Sales	Exh 2 Sch 3 pg 3	2.311	2.231	2.361	2.497	1.886
6	Proposed Nuclear Capacity Factor of 93.21% with Normalized Test Period MWh Sales	Exh 2 Sch 2 pg 3	2.245	2.161	2.313	2.462	1.735
	Proposed Fuel and Fuel-Related Cost Factors using Proposed Nuclear Capacity Factor of 93.21% with Projected Billing Period MWh Sales						
7	Fuel and Fuel-Related Costs excluding Purchased Capacity	Exh 2 Sch 1 pg 2	2.007	1.929	2.019	2.002	1.481
8	Renewable and Qualifying Facilities Purchased Power Capacity	Exh 2 Sch 1 pg 2	0.122	0.133	0.114	0.068	-
9	Total adjusted Fuel and Fuel-Related Costs Factors	Sum	2.129	2.062	2.133	2.070	1.481
10	EMF Increment/(Decrement)	Exh 2 Sch 1 pg 2	0.121	0.102	0.184	0.396	0.270
11	EMF Interest Decrement, if applicable	n/a	-	-	-	-	-
12	Proposed Net Fuel and Fuel-Related Costs Factors	Exh 2 Sch 1 pg 2	2.250	2.164	2.317	2.466	1.751

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 93.21% with Projected Billing Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 3-4	29,337,015	0.5871	$ 172,223,158
2	Coal	Workpaper 3 - 4	7,518,351	2.7226	204,691,540
3	Gas - CT and CC	Workpaper 3 - 4	21,918,020	2.5023	548,461,501
4	Reagents & Byproducts	Workpaper 5	-		34,165,968
5	Total Fossil	Sum of Lines 2 - 4	29,436,371		787,319,008
6	Hydro	Workpaper 3	647,824		-
7	Net Pumped Storage		-		-
8	Total Hydro	Sum of Lines 6 - 7	647,824		-
9	Utility Owned Solar Generation	Workpaper 3	265,105		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	59,686,315		959,542,167
11	Purchases	Workpaper 3 - 4	10,164,587		473,223,121
12	JDA Savings Shared	Workpaper 5	-		(16,262,245)
13	Total Purchases	Sum of Lines 11 - 12	10,164,587		456,960,876
14	Total Generation and Purchases	Line 10 + Line 13	69,850,902		1,416,503,043
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(5,577,243)		(118,111,645)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(2,310,113)		-
					-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16	-		$ 1,298,391,398
18	Projected System MWh Sales for Fuel Factor	Workpaper 3	61,963,546		61,963,546
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 /Line 18 / 10			2.095

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 93.21% with Projected Billing Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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	16,610,751	1,792,730	10,332,062	9,225,261	380,260	38,341,063
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 23,408,207
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						43,472,451
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 66,880,658
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Workpaper 14						60.86%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 40,706,612
7	Production Plant Allocation Factors	Workpaper 14	49.74%	5.87%	28.87%	15.52%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 20,247,836	$ 2,389,757	$ 11,752,681	$ 6,316,338	$ -	$ 40,706,612
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.122	0.133	0.114	0.068	-	0.106
	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	2.007	1.929	2.019	2.002	1.481	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.122	0.133	0.114	0.068	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.129	2.062	2.133	2.070	1.481	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.121	0.102	0.184	0.396	0.270	
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	2.250	2.164	2.317	2.466	1.751	

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 93.21% with Projected Billing Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Harrington Exhibit 2
Schedule 1

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 1250 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	16,610,751	$ 1,778,932,451	$ (1,618,958)	-0.1%	(0.010)	2.260	2.250
2	Small General Service	1,792,730	210,551,207	(191,617)	-0.1%	(0.011)	2.175	2.164
3	Medium General Service	10,332,062	794,800,067	(723,326)	-0.1%	(0.007)	2.324	2.317
4	Large General Service	9,225,261	495,955,852	(451,356)	-0.1%	(0.005)	2.471	2.466
5	Lighting	380,260	90,132,820	(82,027)	-0.1%	(0.022)	1.773	1.751
6	NC Retail	38,341,063	$ 3,370,372,397	$ (3,067,284)				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 8	$ 1,299,142,062
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	66,880,658
9	Adjusted System Other Fuel Costs	Line 7 - Line 8	$ 1,232,261,405
10	NC Retail Allocation % - sales at generation	Workpaper 11	62.22%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 766,713,046
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	40,706,612
13	NC Retail Total Fuel Costs before 2.5% Purchase Power Test	Line 11 + Line 12	$ 807,419,658
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 807,419,658
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,341,063
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 / 10	2.106
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.199
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	2.305
	Total Current Composite Fuel Rate - Docket E-2 Sub 1250:		
21	Current composite Fuel Rate cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17	2.142
22	Current composite EMF Rate cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18	0.171
23	Current composite EMF Interest cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21-23	2.313
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.008)
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,341,063
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$ (3,067,284)

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 93.21% with Normalized Test Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 3-4	29,337,015	0.5871	$	172,223,158
2	Coal	Workpaper 15	6,957,371	2.7226		189,418,528
3	Gas - CT and CC	Workpaper 3-4	21,918,020	2.5023		548,461,501
4	Reagents & Byproducts	Workpaper 4	-			34,165,968
5	Total Fossil	Sum of Lines 2 - 4	28,875,391			772,045,997
6	Hydro	Workpaper 3	647,824			-
7	Net Pumped Storage		-			-
8	Total Hydro	Sum of Lines 6 - 7	647,824			-
9	Utility Owned Solar Generation	Workpaper 3	265,105			-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	59,125,335			944,269,155
11	Purchases	Workpaper 3 - 4	10,164,587			473,223,121
12	JDA Savings Shared	Workpaper 5	-			(16,262,245)
13	Total Purchases	Sum of Lines 11 - 12	10,164,587			456,960,876
14	Total Generation and Purchases	Line 10 + Line 13	69,289,922			1,401,230,031
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(5,577,243)			(118,111,645)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(2,289,210)			-
						-
17	System Fuel Expense for Fuel Factor	Lines 14 + Line 15 + Line 16	-		$	1,283,118,386
18	Normalized Test Period MWh Sales for Fuel Factor	Exhibit 4	61,423,469			61,423,469
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10				2.089

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 93.21% with Normalized Test Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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	16,726,846	2,204,123	10,208,757	8,282,234	341,894	37,763,854
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 23,408,207
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						43,472,451
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 66,880,658
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Workpaper 14						60.86%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 40,706,612
7	Production Plant Allocation Factors	Workpaper 14	49.74%	5.87%	28.87%	15.52%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 20,247,836	$ 2,389,757	$ 11,752,681	$ 6,316,338	$ -	$ 40,706,612
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.121	0.108	0.115	0.076	-	0.108
	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	2.003	1.951	2.014	1.990	1.465	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.121	0.108	0.115	0.076	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.124	2.059	2.129	2.066	1.465	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.121	0.102	0.184	0.396	0.270	
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	2.245	2.161	2.313	2.462	1.735	

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 93.21% with Normalized Test Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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 1250 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	16,726,846	$ 1,778,932,451	$ (2,591,202)	-0.2%	(0.015)	2.260	2.245
2	Small General Service	2,204,123	210,551,207	(306,690)	-0.2%	(0.014)	2.175	2.161
3	Medium General Service	10,208,757	794,800,067	(1,157,710)	-0.2%	(0.011)	2.324	2.313
4	Large General Service	8,282,234	495,955,852	(722,412)	-0.2%	(0.009)	2.471	2.462
5	Lighting	341,894	90,132,820	(131,288)	-0.2%	(0.038)	1.773	1.735
6	NC Retail	37,763,854	$ 3,370,372,397	$ (4,909,302)				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 9	$ 1,283,869,051
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	66,880,658
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,216,988,393
10	NC Retail Allocation % - sales at generation	Workpaper 11	61.84%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 752,585,622
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	40,706,612
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 793,292,234
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 17	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 793,292,234
16	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A	37,763,854
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.101
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.199
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	2.300
	Total Current Composite Fuel Rate - Docket E-2 Sub 1250:		
21	Current composite Fuel Rate cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17	2.142
22	Current composite EMF Rate cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18	0.171
23	Current composite EMF Interest cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.313
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.013)
26	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A	37,763,854
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$ (4,909,302)

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 93.18% with Projected Billing Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 2	27,892,328	0.5871	$ 163,742,110
2	Coal	Workpaper 15	8,963,038	2.7226	244,024,009
3	Gas - CT and CC	Workpaper 3 - 4	21,918,020	2.5023	548,461,501
4	Reagents & Byproducts	Workpaper 5	-		34,165,968
5	Total Fossil	Sum of Lines 2 - 4	30,881,058		826,651,478
6	Hydro	Workpaper 3	647,824		-
7	Net Pumped Storage		-		-
8	Total Hydro	Sum of Lines 6 - 7	647,824		-
9	Utility Owned Solar Generation	Workpaper 3	265,105		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	59,686,315		990,393,588
11	Purchases	Workpaper 3 - 4	10,164,587		473,223,121
12	JDA Savings Shared	Workpaper 5	-		(16,262,245)
13	Total Purchases	Sum of Lines 11- 12	10,164,587		456,960,876
14	Total Generation and Purchases	Line 10 + Line 13	69,850,902		1,447,354,464
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(5,577,243)		(118,111,645)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(2,310,113)		-
					-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16	-		$ 1,329,242,819
18	System MWh Sales for Fuel Factor	Workpaper 3	61,963,546		61,963,546
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10			2.145

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 93.18% with Projected Billing Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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	16,610,751	1,792,730	10,332,062	9,225,261	380,260	38,341,063
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 23,408,207
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						43,472,451
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 66,880,658
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Workpaper 14						60.86%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 40,706,612
7	Production Plant Allocation Factors	Workpaper 14	49.74%	5.87%	28.87%	15.52%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 20,247,836	$ 2,389,757	$ 11,752,681	$ 6,316,338	$ -	$ 40,706,612
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.122	0.133	0.114	0.068	-	0.106
	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	2.068	1.996	2.063	2.033	1.616	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.122	0.133	0.114	0.068	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.190	2.129	2.177	2.101	1.616	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.121	0.102	0.184	0.396	0.270	
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	2.311	2.231	2.361	2.497	1.886	

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 93.18% with Projected Billing Period MWh Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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 1250 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	16,610,751	$ 1,778,932,451	$ 8,499,532	0.5%	0.051	2.260	2.311
2	Small General Service	1,792,730	210,551,207	1,005,989	0.5%	0.056	2.175	2.231
3	Medium General Service	10,332,062	794,800,067	3,797,462	0.5%	0.037	2.324	2.361
4	Large General Service	9,225,261	495,955,852	2,369,619	0.5%	0.026	2.471	2.497
5	Lighting	380,260	90,132,820	430,644	0.5%	0.113	1.773	1.886
6	NC Retail	38,341,063	$ 3,370,372,397	$ 16,103,246				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 10	$ 1,329,993,484
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	66,880,658
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,263,112,826
10	NC Retail Allocation % - sales at generation	Workpaper 11	62.22%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 785,908,801
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	40,706,612
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 826,615,412
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 826,615,412
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,341,063
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.156
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.199
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	2.355
	Total Current Composite Fuel Rate - Docket E-2 Sub 1250:		
21	Current composite Fuel Rate cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17	2.142
22	Current composite EMF Rate cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18	0.171
23	Current composite EMF Interest cents/kWh	2020 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.313
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	0.042
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,341,063
27	Increase/(Decrease) in Fuel Costs	Line 25* Line 26 * 10	$ 16,103,246

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, 2021
Docket No. E-2, Sub 1272

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 2020 (Sub 1204)	2.030	2.301	2,545,361	$ (6,896,271)	-	$ (6,896,271)
2	May	2.691	2.301	2,433,609	9,480,912	-	9,480,912
3	June	2.505	2.306	2,914,205	5,783,430	-	5,783,430
4	July	2.953	2.312	3,515,386	22,516,948	$ (176,566)	22,340,382
5	August	2.667	2.313	3,795,408	13,453,204	-	13,453,204
6	September	2.211	2.311	3,430,875	(3,443,181)	70,110	(3,373,071)
7	October	1.881	2.300	2,730,391	(11,437,511)	-	(11,437,511)
8	November	2.269	2.318	2,807,755	(1,375,991)	-	(1,375,991)
9	December (New Rates - Sub 1250)	2.811	2.235	2,899,316	16,716,407	(757,380)	15,959,027
10	January 2021	2.456	2.137	3,363,691	10,727,492	(25,476)	10,702,016
11	February	2.554	2.136	3,381,318	14,138,429	-	14,138,429
12	March	2.093	2.142	3,064,503	(1,514,744)	3,955,719	2,440,975
13	Total Test Period			36,881,818	$ 68,149,123	$ 3,066,407	$ 71,215,530
14	Booked 12-month (Over) / Under Recovery						$ 71,215,530
15	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(1,490,401)
16	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						5,254,561
17	Total Adjusted (Over) / Under Recovery Request						$ 74,979,691
18	Normalized Test Period MWh Sales	Exhibit 4					37,763,854
19	Experience Modification Increment / (Decrement) cents/KWh						0.199

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Twelve Months Ended March 31, 2021
Docket No. E-2, Sub 1272

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 2020 (Sub 1204)		2.157	2.326	1,035,556	$ (1,754,749)		$ (1,754,749)
2	May		2.910	2.326	973,663	5,684,146		5,684,146
3	June		2.560	2.326	1,229,087	2,880,119		2,880,119
4	July		2.823	2.326	1,591,426	7,917,186	$ (268,437)	7,648,749
5	August		2.523	2.326	1,731,091	3,409,038		3,409,038
6	September		2.216	2.326	1,477,145	(1,629,734)	29,993	(1,599,741)
7	October		2.218	2.326	999,660	(1,082,331)		(1,082,331)
8	November		2.805	2.326	974,858	4,671,908		4,671,908
9	December (New Rates - Sub 1250)		2.330	2.246	1,449,087	1,216,889	(303,301)	913,587
10	January 2021		1.999	2.085	1,710,979	(1,459,013)	(1,910)	(1,460,924)
11	February		2.074	2.080	1,721,621	(102,840)		(102,840)
12	March		1.895	2.080	1,402,837	(2,596,107)	1,714,772	(881,335)
13	Total Test Period				16,297,009	$ 17,154,511	$ 1,171,116	$ 18,325,627
14	Booked 12-month (Over) / Under Recovery							$ 18,325,627
15	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order							(758,847)
16	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order							2,675,395
17	Total Adjusted (Over) / Under Recovery Request							$ 20,242,174
18	Normalized Test Period MWh Sales	Exhibit 4						16,726,846
19	Experience Modification Increment (Decrement) cents/KWh							0.121

Notes:
Totals may not foot due to rounding.

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, 2021
Docket No. E-2, Sub 1272

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 2020 (Sub 1204)	2.312	2.499	115,292	$ (215,689)		$ (215,689)
2	May	3.079	2.499	109,854	637,579		637,579
3	June	2.701	2.499	138,935	281,246		281,246
4	July	3.075	2.499	176,311	1,015,020	$ 23,319	1,038,339
5	August	2.719	2.499	193,028	425,510		425,510
6	September	2.169	2.499	181,374	(597,971)	3,569	(594,402)
7	October	2.051	2.499	129,986	(582,950)		(582,950)
8	November	2.646	2.499	123,484	181,028		181,028
9	December (New Rates - Sub 1250)	2.495	2.388	152,191	162,469	(25,932)	136,538
10	January 2021	2.307	2.136	166,543	284,674	(220)	284,454
11	February	2.423	2.126	165,183	490,274		490,274
12	March	1.981	2.126	150,974	(218,705)	192,553	(26,152)
13	Total Test Period			1,803,155	$ 1,862,486	$ 193,289	$ 2,055,775
14	Booked 12-month (Over) / Under Recovery						$ 2,055,775
15	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(72,809)
16	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						256,695
17	Total Adjusted (Over) / Under Recovery Request						$ 2,239,661
18	Normalized Test Period MWh Sales	Exhibit 4					2,204,123
19	Experience Modification Increment (Decrement) cents/KWh						0.102

Notes:
Totals may not foot due to rounding.

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, 2021
Docket No. E-2, Sub 1272

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 2020 (Sub 1204)	2.076	2.456	725,689	$ (2,758,925)		$ (2,758,925)
2	May	2.712	2.456	703,590	1,801,471		1,801,471
3	June	2.560	2.456	831,511	864,855		864,855
4	July	3.106	2.456	976,618	6,347,235	$ 70,747	6,417,982
5	August	2.832	2.456	1,044,407	3,924,048		3,924,048
6	September	2.259	2.456	980,943	(1,932,949)	20,479	(1,912,470)
7	October	1.785	2.456	841,000	(5,646,134)		(5,646,134)
8	November	1.795	2.456	1,037,103	(6,859,713)		(6,859,713)
9	December (New Rates - Sub 1250)	4.024	2.365	572,974	9,502,136	(67,216)	9,434,920
10	January 2021	2.895	2.235	807,302	5,324,375	(1,176)	5,323,199
11	February	2.966	2.228	823,418	6,073,098		6,073,098
12	March	2.236	2.228	811,503	61,221	1,113,083	1,174,304
13	Total Test Period			10,156,058	$ 16,700,718	$ 1,135,917	$ 17,836,634
14	Booked 12-month (Over) / Under Recovery						$ 17,836,634
15	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(362,942)
16	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						1,279,590
17	Total Adjusted (Over) / Under Recovery Request						$ 18,753,282
18	Normalized Test Period MWh Sales	Exhibit 4					10,208,757
19	Experience Modification Increment (Decrement) cents/KWh						0.184

Notes:
Totals may not foot due to rounding.

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, 2021
Docket No. E-2, Sub 1272

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 2020 (Sub 1204)	1.738	2.054	640,188	$ (2,025,940)		$ (2,025,940)
2	May	2.276	2.054	617,957	1,370,134		1,370,134
3	June	2.299	2.054	686,100	1,682,181		1,682,181
4	July	2.985	2.054	742,526	6,912,989	$ (1,352)	6,911,637
5	August	2.726	2.054	798,469	5,364,432		5,364,432
6	September	2.136	2.054	763,017	628,802	15,354	644,156
7	October	1.510	2.054	731,277	(3,981,070)		(3,981,070)
8	November	2.148	2.054	645,055	603,126		603,126
9	December (New Rates - Sub 1250)	2.924	2.079	695,658	5,879,172	(353,131)	5,526,042
10	January 2021	3.170	2.186	651,734	6,415,862	(23,424)	6,392,439
11	February	3.370	2.204	642,842	7,494,221		7,494,221
12	March	2.387	2.204	669,752	1,227,378	897,891	2,125,269
13	Total Test Period			8,284,574	$ 31,571,288	$ 535,339	$ 32,106,627
14	Booked 12-month (Over) / Under Recovery						$ 32,106,627
15	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(283,349)
16	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						998,975
17	Total Adjusted (Over) / Under Recovery Request						$ 32,822,253
18	Normalized Test Period MWh Sales	Exhibit 4					8,282,234
19	Experience Modification Increment (Decrement) cents/KWh						0.396

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Lighting
Twelve Months Ended March 31, 2021
Docket No. E-2, Sub 1272

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 2020 (Sub 1204)	1.725	2.217	28,635	$ (140,968)		$ (140,968)
2	May	2.174	2.217	28,546	(12,418)		(12,418)
3	June	2.480	2.217	28,572	75,029		75,029
4	July	3.355	2.217	28,506	324,518	$ (843)	323,675
5	August	3.379	2.217	28,413	330,176		330,176
6	September	2.529	2.217	28,396	88,671	715	89,386
7	October	1.708	2.217	28,469	(145,026)		(145,026)
8	November	2.318	2.217	27,254	27,660		27,660
9	December (New Rates - Sub 1250)	1.826	1.977	29,406	(44,260)	(7,801)	(52,060)
10	January 2021	2.017	1.421	27,134	161,594	1,254	162,848
11	February	2.042	1.392	28,255	183,676		183,676
12	March	1.431	1.392	29,436	11,469	37,421	48,889
13	Total Test Period			341,023	$ 860,120	$ 30,746	$ 890,867
14	Booked 12-month (Over) / Under Recovery						$ 890,867
15	Adjustment to exclude test period by-product net gain/loss accrued expense per Docket No. E-2 Sub 1204 Order						(12,454)
16	Adjustment to include test period by-product net gain/loss cash payments per Docket No. E-2 Sub 1204 Order						43,908
17	Total Adjusted (Over) / Under Recovery Request						$ 922,320
18	Normalized Test Period MWh Sales	Exhibit 4					341,894
19	Experience Modification Increment (Decrement) cents/KWh						0.270

Notes:
Totals may not foot due to rounding.

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, 2021
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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	59,907,284	36,881,818	16,297,009	1,803,155	10,156,058	8,284,574	341,023
2	Weather MWh Adjustment	Workpaper 9	1,239,910	732,846	295,534	383,515	59,185	(5,387)	0
3	Customer Growth MWh Adjustment	Workpaper 9	276,275	149,190	134,304	17,453	(6,486)	3,047	871
4	Total Normalized Test Period MWh Sales	Sum Lines 1-3	61,423,469	37,763,854	16,726,846	2,204,123	10,208,757	8,282,234	341,894
5	Test Period Fuel and Fuel-Related Revenue *		$ 1,352,449,252	$ 832,575,319					
6	Test Period Fuel and Fuel-Related Expense *		$ 1,472,904,739	$ 903,790,849					
7	Test Period Unadjusted (Over)/Under Recovery	Line 5 - Line 6	$ 120,455,487	$ 71,215,530					

Line No.	Description	2020 Summer Coincidental Peak (CP) KW
8	Total System Peak	12,660,824
9	NC Retail	7,796,217
10	NC Residential Peak	3,877,909
11	NC Small General Service	457,691
12	NC Medium General Service	2,250,899
13	NC Large General Service	1,209,718

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, 2021
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Unit	Rate Case Docket E-2, Sub 1219	Fuel Docket E-2, Sub 1250	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

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Monthly Fuel and Baseload Report for March 2021
Twelve Months Ended March 31, 2021
Docket No. E-2, Sub 1272

Harrington Exhibit 6

March 2021
Monthly Fuel Filing and Baseload Report Cover Sheet

Schedule 1

DUKE ENERGY PROGRESS
SUMMARY OF MONTHLY FUEL REPORT

Docket No. E-2, Sub 1270

Line No.	Fuel Expenses:	MARCH 2021	12 Months Ended MARCH 2021
1	Total Fuel and Fuel-Related Costs	$ 100,331,366	$ 1,464,236,335
	MWH sales:		
2	Total System Sales	5,029,404	65,887,927
3	Less intersystem sales	230,017	5,980,643
4	Total sales less intersystem sales	4,799,387	59,907,284
5	Total fuel and fuel-related costs (¢/KWH) (Line 1/Line 4)	2.091	2.444
6	Current fuel & fuel-related cost component (¢/KWH) (per Schedule 4, Line 5a Total)	2.142	
	Generation Mix (MWH):		
	Fossil (By Primary Fuel Type):		
7	Coal	288,885	7,475,010
8	Oil	3,534	57,288
9	Natural Gas - Combustion Turbine	151,112	1,446,566
10	Natural Gas - Combined Cycle	1,405,302	19,656,637
11	Biogas	1,450	23,280
12	Total Fossil	1,850,284	28,658,781
13	Nuclear	2,137,964	29,445,201
14	Hydro - Conventional	95,428	919,344
15	Solar Distributed Generation	19,594	243,635
16	Total MWH generation	4,103,270	59,266,961

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 1270

Description	MARCH 2021	12 Months Ended MARCH 2021
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0501110 coal consumed - steam	$ 11,337,777	$ 308,734,956
0501310 fuel oil consumed - steam	508,607	4,966,878
Total Steam Generation - Account 501	11,846,384	313,701,834
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	12,487,630	172,857,049
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	7,679,784	56,847,343
0547000 natural gas consumed - Combined Cycle	40,868,247	535,076,531
0547106 biogas consumed - Combined Cycle	63,807	980,368
0547200 fuel oil consumed	67,114	9,509,937
Total Other Generation - Account 547	48,678,952	602,414,179
Reagents		
Catalyst Depreciation	-	459,696
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	593,509	13,132,294
Total Reagents	593,509	13,591,990
By-products		
Net proceeds from sale of by-products	748,960	12,766,522
Total By-products	748,960	12,766,522
Total Fossil and Nuclear Fuel Expenses		
Included in Base Fuel Component	74,355,435	1,115,331,574
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (PURPA)	1,867,502	41,783,442
Capacity component of purchased power (renewables)	2,216,422	39,960,001
Fuel and fuel-related component of purchased power	28,389,037	394,086,222
Total Purchased Power and Net Interchange - Account 555	32,472,961	475,829,665
Less:		
Fuel and fuel-related costs recovered through intersystem sales	6,497,020	126,708,912
Solar Integration Charge	10	(6,560)
Miscellaneous Fees Collected	-	222,552
Total Fuel Credits - Accounts 447/456	6,497,030	126,924,904
Total Fuel and Fuel-Related Costs	$ 100,331,366	$ 1,464,236,335

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

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

MARCH 2021

Purchased Power	Total	Capacity	Non-capacity			
Economic Purchases	**$**	**$**	**mWh**	**Fuel $**	**Fuel-related $**	**Not Fuel $ Not Fuel-related $**
Broad River Energy, LLC	$ 3,365,900	$ 2,445,642	13,004	$ 500,072	$ 420,186	-
City of Fayetteville	865,467	708,500	755	133,913	23,054	-
DE Carolinas - Native Load Transfer	5,054,174	-	216,074	4,528,684	532,667	$ (7,177)
DE Carolinas - Native Load Transfer Benefit	1,372,518	-	-	1,372,518	-	-
DE Carolinas - Fees	807	-	-	-	807	-
Haywood EMC	28,000	28,000	-	-	-	-
NCEMC	3,184,724	2,761,898	9,649	406,921	15,905	-
PJM Interconnection, LLC	46,081	-	1,600	29,492	16,589	-
Southern Company Services	5,023,316	2,388,167	59,881	2,325,656	309,493	-
	$ 18,940,987	**$ 8,332,207**	**300,963**	**$ 9,297,256**	**$ 1,318,701**	**$ (7,177)**
Renewable Energy Purchases						
REPS	$ 10,963,881	-	160,155	-	$ 10,963,881	-
DERP Qualifying Facilities	60,015	-	1,321	-	57,879	$ 2,136
	$ 11,023,896	**-**	**161,476**	**-**	**$ 11,021,760**	**$ 2,136**
HB589 PURPA Purchases						
Other Qualifying Facilities	$ 10,179,006	-	179,195	-	$ 10,179,006	-
	$ 10,179,006	**-**	**179,195**	**-**	**$ 10,179,006**	**-**
Non-dispatchable Purchases						
DE Carolinas - Reliability	$ 1,052,684	-	26,702	$ 642,137	-	$ 410,547
Energy Imbalance	14,257	-	591	13,110	-	1,147
Generation Imbalance	1,087	-	70	991	-	96
	$ 1,068,028	**-**	**27,363**	**$ 656,238**	**-**	**$ 411,790**
Total Purchased Power	**$ 41,211,917**	**$ 8,332,207**	**668,997**	**$ 9,953,494**	**$ 22,519,467**	**$ 406,749**

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

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

MARCH 2021

Sales	Total $	Capacity $	mWh	Non-capacity Fuel $	Non-fuel $
Market Based:					
NCEMC Purchase Power Agreement	$ 1,026,299	$ 652,500	12,078	$ 280,411	$ 93,388
PJM Interconnection, LLC	224,005	-	13,150	236,314	(12,309)
Other:					
DE Carolinas - Native Load Transfer	5,324,959	-	204,764	5,065,194	259,765
DE Carolinas - Native Load Transfer Benefit	915,117	-	-	915,117	-
Generation Imbalance	(46)	-	25	(16)	(30)
Total Intersystem Sales	**$ 7,490,334**	**$ 652,500**	**230,017**	**$ 6,497,020**	**$ 340,814**

* 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 2021

Purchased Power	Total	Capacity	Non-capacity			
Economic Purchases	**$**	**$**	**mWh**	**Fuel $**	**Fuel-related $**	**Not Fuel $ Not Fuel-related $**
Broad River Energy, LLC	$ 63,649,052	$ 47,429,336	285,735	$ 9,342,861	$ 6,876,855	-
City of Fayetteville	12,929,286	12,682,500	2,372	223,732	23,054	-
DE Carolinas - Native Load Transfer	25,856,418	-	1,118,546	21,033,084	4,504,009	$ 319,324
DE Carolinas - Native Load Transfer Benefit	4,377,577	-	-	4,377,577	-	-
DE Carolinas - Fees	(390)	-	-	-	(390)	-
Haywood EMC	340,950	340,950	-	-	-	-
NCEMC	42,532,734	37,015,609	143,738	5,198,584	318,541	-
PJM Interconnection, LLC	141,409	-	5,400	81,332	60,077	-
Southern Company Services	55,853,341	21,551,558	1,164,832	29,489,715	4,812,067	-
	$ 205,680,377	**$ 119,019,953**	**2,720,623**	**$ 69,746,885**	**$ 16,594,213**	**$ 319,324**
Renewable Energy Purchases						
REPS	$ 191,980,665	-	2,759,382	-	$ 191,980,665	-
DERP Qualifying Facilities	1,196,506	-	29,224	-	1,139,891	$ 56,615
DERP Net Metering Excess Generation	24,958	$ 4,305	582	-	-	20,653
	$ 193,202,129	**$ 4,305**	**2,789,188**	**-**	**$ 193,120,556**	**$ 77,268**
HB589 PURPA Purchases						
Other Qualifying Facilities	$ 195,211,231	-	3,437,943	-	$ 195,211,231	-
CPRE - Purchased Power	(10,000)	-	-	-	-	$ (10,000)
	$ 195,201,231	**-**	**3,437,943**	**-**	**$ 195,211,231**	**(10,000)**
Non-dispatchable Purchases						
DE Carolinas - Emergency	$ 113,361	-	1,822	$ 69,150	-	$ 44,211
DE Carolinas - Reliability	1,570,324	-	41,282	957,897	-	612,427
Dominion Energy South Carolina - Emergency	(2,075)	-	-	(1,266)	-	(809)
Energy Imbalance	128,289	-	5,979	119,722	-	8,567
Generation Imbalance	15,435	-	828	11,277	-	4,158
	$ 1,825,334	**-**	**49,911**	**$ 1,156,780**	**-**	**$ 668,554**
Total Purchased Power	**$ 595,909,071**	**$ 119,024,258**	**8,997,665**	**$ 70,903,665**	**$ 404,926,000**	**$ 1,055,146**

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 2021

Sales	Total $	Capacity $	mWh	Non-capacity Fuel $	Non-fuel $
Utilities:					
DE Carolinas - As Available Capacity	$ 138,997	$ 138,997	-	-	-
DE Carolinas - Emergency	44,900	-	392	$ 27,389	$ 17,511
Market Based:					
NCEMC Purchase Power Agreement	11,280,318	7,830,000	112,127	2,380,641	1,069,677
PJM Interconnection, LLC	1,939,935	-	58,216	1,310,043	629,892
Other:					
DE Carolinas - Native Load Transfer	115,882,090	-	5,809,742	109,214,502	6,667,587
DE Carolinas - Native Load Transfer Benefit	13,776,190	-	-	13,776,190	-
Generation Imbalance	(790)	-	166	147	(936)
Total Intersystem Sales	**$ 143,061,640**	**$ 7,968,997**	**5,980,643**	**$ 126,708,912**	**$ 8,383,731**

* 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 2021

Line No.			Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total
1	1a. System Retail kWh sales	Input						4,799,386,806
	1b. System kWh Sales at generation	Input						4,949,536,527
2	2a. DERP Net Metered kWh generation	Input						2,576,658
	2b. Line loss percentage from Cost of Service	Input Annually						3.334%
	2c. DERP Net Metered kWh at generation	L2a * (1 + 2b)						2,662,564
3	Adjusted System kWh sales	L1b + L2c						4,952,199,091
4	4a. N.C. Retail kWh sales	Input	1,402,837,404	150,973,929	811,503,264	669,751,854	29,436,338	3,064,502,789
	4b. Line loss percentage from Cost of Service	Input Annually	3.654%	3.654%	3.563%	2.988%	3.653%	
	4c. NC kWh Sales at generation	4a * (1+4b)	1,454,097,083	156,490,516	840,417,125	689,764,039	30,511,647	3,171,280,410
	4d. NC allocation % by customer class	Calculated	45.852%	4.935%	26.501%	21.750%	0.962%	
	4e. NC retail % of actual system total	L4c NC Total / L1b Total System						64.072%
	4f. NC retail % of adjusted system total	L4c NC Total / L3 Total System						64.038%
5	Approved fuel and fuel-related rates (¢/kWh)							
	5a Billed rates by class (¢/kWh)	Input Annually	2.080	2.126	2.228	2.204	1.392	2.142
	5b Billed fuel expense	L4a * L5a / 100	$29,179,018	$3,209,706	$18,080,293	$14,761,331	$409,754	$65,640,101
6	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)							
	6a NC Docket E-2, Sub 1250 allocation factor	Input Annually	41.194%	4.593%	28.250%	25.280%	0.683%	100.00%
	6b System incurred expense	Input						$96,305,740
	6c NC incurred expense by class	L4f * L6a * L6b	$25,405,275	$2,832,607	$17,422,416	$15,590,750	$421,222	$61,672,270
	6d NC Incurred base fuel rates (¢/kWh)	L6c / L4a * 100	1.81099	1.87622	2.14693	2.32784	1.43096	2.01247
7	Incurred renewable purchased power capacity rates (¢/kWh)							
	7a NC retail production plant %	Input Annually						60.067%
	7b Production plant allocation factors	Input Annually	48.006%	6.457%	29.314%	16.223%	0.000%	100.00%
	7c System incurred expense	Input						$4,083,924
	7d NC incurred renewable capacity expense	L7a* L7b* L7c	$1,177,637	$158,393	$719,098	$397,959	$0	$2,453,087
	7e NC incurred rates by class	L7d / L4a * 100	0.08395	0.10491	0.08861	0.05942	-	0.08005
8	Total incurred rates by class (¢/kWh)	L6h + 7e	1.8949	1.9811	2.2355	2.3873	1.4310	
9	Difference in ¢/kWh (incurred - billed)	L8 - L5a	(0.18506)	(0.14486)	0.00754	0.18326	0.03896	
10	(Over) / under recovery [See footnote]	L9 * L4a / 100	**($2,596,107)**	**($218,705)**	**$61,221**	**$1,227,378**	**$11,468**	**($1,514,745)**
11	Adjustments	Input	$ 1,714,772	$ 192,553	$ 1,113,083	$ 897,891	$ 37,421	$ 3,955,719
12	Total (over) / under recovery [See footnote]	L10 + L11	**($881,335)**	**($26,152)**	**$1,174,304**	**$2,125,269**	**$48,889**	**$2,440,974**
13	Total System Incurred Expenses							$100,389,664
14	Less: Jurisdictional allocation adjustment	Input						58,297
15	Total Fuel and Fuel-related Costs per Schedule 2							$100,331,366
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 2020	($6,896,271)	($1,754,749)	($215,689)	($2,758,925)	($2,025,940)	($140,968)	($6,896,271)
May 2020	2,584,641	5,684,146	637,579	1,801,471	1,370,134	(12,418)	9,480,912
June 2020	8,368,071	2,880,119	281,246	864,855	1,682,181	75,029	5,783,430
July 2020	30,708,453	7,648,749	1,038,339	6,417,982	6,911,637	323,675	22,340,382
August 2020	44,161,657	3,409,038	425,510	3,924,048	5,364,432	330,176	13,453,204
September 2020	40,788,586	(1,599,741)	(594,402)	(1,912,470)	644,156	89,386	(3,373,071)
October 2020	29,351,075	(1,082,331)	(582,950)	(5,646,134)	(3,981,070)	(145,026)	(11,437,511)
November 2020	27,975,084	4,671,908	181,028	(6,859,713)	603,126	27,660	(1,375,991)
December 2020	43,934,111	913,587	136,538	9,434,920	5,526,042	(52,060)	15,959,027
January 2021	54,636,127	(1,460,924)	284,454	5,323,199	6,392,439	162,848	10,702,016
February 2021	68,774,556	(102,840)	490,274	6,073,098	7,494,221	183,676	14,138,429
March 2021	71,215,531	(881,335)	(26,152)	1,174,304	2,125,269	48,889	2,440,975
Total		**$18,325,627**	**$2,055,775**	**$17,836,635**	**$32,106,627**	**$890,867**	**$71,215,531**

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 adjustments.

Duke Energy Progress
Fuel and Fuel Related Cost Report
MARCH 2021

Schedule 5
Page 1 of 2

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	$2,061,894	$15,532,843	-	-	-	-	-
Oil	170,537	480,943	$1,041,674	-	-	-	-
Gas - CC	-	-	8,943,847	$14,520,418	$12,723,449	$4,680,533	-
Gas - CT	-	-	296,206	4,364,668	190,727	-	-
Biogas	-	-	-	330,810	-	-	-
Total	$2,232,431	$16,013,786	$10,281,727	$19,215,896	$12,914,176	$4,680,533	-
Average Cost of Fuel Purchased (¢/MBTU)							
Coal	353.09	249.47	-	-	-	-	-
Oil	1,369.34	1,412.21	2,025.30	-	-	-	-
Gas - CC	-	-	399.76	364.51	468.85	638.94	-
Gas - CT	-	-	470.43	390.40	1,298.70	-	-
Biogas	-	-	-	3,043.61	-	-	-
Weighted Average	374.31	255.79	401.70	375.87	473.32	638.94	-
Cost of Fuel Burned ($)							
Coal	-	$11,337,777	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	-	508,608	$829	-	-	-	-
Gas - CC	-	-	8,943,847	$14,520,418	$12,723,449	$4,680,533	-
Gas - CT	-	-	296,206	4,364,668	190,727	-	-
Biogas	-	-	-	330,810	-	-	-
Nuclear	-	-	-	-	-	-	-
Total	-	$11,846,385	$9,240,882	$19,215,896	$12,914,176	$4,680,533	-
Average Cost of Fuel Burned (¢/MBTU)							
Coal	-	310.49	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	-	1,227.69	1,564.15	-	-	-	-
Gas - CC	-	-	399.76	364.51	468.85	638.94	-
Gas - CT	-	-	470.43	390.40	1,298.70	-	-
Biogas	-	-	-	3,043.61	-	-	-
Nuclear	-	-	-	-	-	-	-
Weighted Average	-	320.78	401.73	375.87	473.32	638.94	-
Average Cost of Generation (¢/kWh)							
Coal	-	3.84	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	-	14.52	25.81	-	-	-	-
Gas - CC	-	-	2.58	2.51	3.39	4.46	-
Gas - CT	-	-	7.03	5.79	13.80	-	-
Biogas	-	-	-	22.82	-	-	-
Nuclear	-	-	-	-	-	-	-
Weighted Average	-	3.96	2.64	2.93	3.43	4.46	-
Burned MBTU's							
Coal	-	3,651,542	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	-	41,428	53	-	-	-	-
Gas - CC	-	-	2,237,280	3,983,544	2,713,749	732,547	-
Gas - CT	-	-	62,965	1,117,990	14,686	-	-
Biogas	-	-	-	10,869	-	-	-
Nuclear	-	-	-	-	-	-	-
Total	-	3,692,970	2,300,298	5,112,403	2,728,435	732,547	-
Net Generation (mWh)							
Coal	(6,496)	295,381	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	-	3,504	3	-	-	-	-
Gas - CC	-	-	345,991	578,866	375,526	104,919	-
Gas - CT	-	-	4,214	75,346	1,382	-	-
Biogas	-	-	-	1,450	-	-	-
Nuclear	-	-	-	-	-	-	-
Hydro (Total System)							
Solar (Total System)							
Total	(6,496)	298,885	350,208	655,662	376,908	104,919	-
Cost of Reagents Consumed ($)							
Ammonia	$10,413	$71,325	-	$13,485	-	-	-
Limestone	-	359,201	-	-	-	-	-
Re-emission Chemical	-	-	-	-	-	-	-
Sorbents	1,510	137,575	-	-	-	-	-
Urea	-	-	-	-	-	-	-
Total	$11,923	$568,101	-	$13,485	-	-	-

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.

Duke Energy Progress
Fuel and Fuel Related Cost Report
MARCH 2021

Description	Darlington CT	Wayne County CT	Weatherspoon CT	Brunswick Nuclear	Harris Nuclear	Robinson Nuclear	Current Month	Total 12 ME MARCH 2021
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	-	-	$17,594,737	$242,667,570
Oil	-	-	-	-	-	-	1,693,154	5,983,107
Gas - CC	-	-	-	-	-	-	40,868,247	535,076,532
Gas - CT	$2,016	$2,826,153	$14	-	-	-	7,679,784	56,847,343
Biogas	-	-	-	-	-	-	330,810	4,653,130
Total	$2,016	$2,826,153	$14	-	-	-	$68,166,732	$845,227,682
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	-	-	258.35	367.13
Oil	-	-	-	-	-	-	1,728.71	1,299.29
Gas - CC	-	-	-	-	-	-	422.76	381.61
Gas - CT	380.38	353.86	-	-	-	-	384.98	331.67
Biogas	-	-	-	-	-	-	3,043.61	2,822.56
Weighted Average	380.38	353.86	-	-	-	-	366.86	377.22
Cost of Fuel Burned ($)								
Coal	-	-	-	-	-	-	$11,337,777	$307,088,787
Oil - CC	-	-	-	-	-	-	-	227,065
Oil - Steam/CT	$35,200	$1,587	$29,498	-	-	-	575,722	14,249,752
Gas - CC	-	-	-	-	-	-	40,868,247	535,076,532
Gas - CT	2,016	2,826,153	14	-	-	-	7,679,784	56,847,343
Biogas	-	-	-	-	-	-	330,810	4,653,130
Nuclear	-	-	-	$4,839,760	$4,213,898	$3,433,972	12,487,630	172,857,049
Total	$37,216	$2,827,740	$29,512	$4,839,760	$4,213,898	$3,433,972	$73,279,970	$1,090,999,658
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	-	-	310.49	358.50
Oil - CC	-	-	-	-	-	-	-	1,522.90
Oil - Steam/CT	1,722.96	1,743.96	1,591.05	-	-	-	1,266.19	1,507.90
Gas - CC	-	-	-	-	-	-	422.76	381.61
Gas - CT	380.38	353.86	-	-	-	-	384.98	331.67
Biogas	-	-	-	-	-	-	3,043.61	2,822.56
Nuclear	-	-	-	56.86	56.40	57.90	56.99	56.42
Weighted Average	1,446.40	354.01	1,591.80	56.86	56.40	57.90	196.55	198.17
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	-	-	3.92	4.11
Oil - CC	-	-	-	-	-	-	-	14.55
Oil - Steam/CT	969.43	19.96	184.36	-	-	-	16.29	25.57
Gas - CC	-	-	-	-	-	-	2.91	2.72
Gas - CT	-	4.03	-	-	-	-	5.08	3.93
Biogas	-	-	-	-	-	-	22.82	19.99
Nuclear	-	-	-	0.59	0.57	0.59	0.58	0.59
Weighted Average	-	4.03	184.45	0.59	0.57	0.59	1.79	1.84
Burned MBTU's								
Coal	-	-	-	-	-	-	3,651,542	85,659,068
Oil - CC	-	-	-	-	-	-	-	14,910
Oil - Steam/CT	2,043	91	1,854	-	-	-	45,469	945,007
Gas - CC	-	-	-	-	-	-	9,667,120	140,214,736
Gas - CT	530	798,674	-	-	-	-	1,994,845	17,139,676
Biogas	-	-	-	-	-	-	10,869	164,855
Nuclear	-	-	-	8,511,141	7,471,339	5,930,357	21,912,837	306,385,599
Total	2,573	798,765	1,854	8,511,141	7,471,339	5,930,357	37,282,682	550,523,851
Net Generation (mWh)								
Coal	-	-	-	-	-	-	288,885	7,475,010
Oil - CC	-	-	-	-	-	-	-	1,561
Oil - Steam/CT	4	8	16	-	-	-	3,534	55,727
Gas - CC	-	-	-	-	-	-	1,405,302	19,656,637
Gas - CT	(21)	70,191	-	-	-	-	151,112	1,446,566
Biogas	-	-	-	-	-	-	1,450	23,280
Nuclear	-	-	-	815,304	740,789	581,871	2,137,964	29,445,201
Hydro (Total System)							95,428	919,344
Solar (Total System)							19,594	243,635
Total	(17)	70,199	16	815,304	740,789	581,871	4,103,270	59,266,961
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	-	-	$95,223	$1,821,659
Limestone	-	-	-	-	-	-	359,201	7,735,380
Re-emission Chemical	-	-	-	-	-	-	-	-
Sorbents	-	-	-	-	-	-	139,085	3,204,887
Urea	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	$593,509	$12,761,926

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
MARCH 2021

Schedule 6
Page 1 of 2

Description	Mayo	Roxboro	Asheville	Smith Energy Complex	Sutton	Lee	Blewett
Coal Data:							
Beginning balance	278,734	691,677	-	-	-	-	-
Tons received during period	24,237	246,531	-	-	-	-	-
Inventory adjustments	-	-	-	-	-	-	-
Tons burned during period	-	145,272	-	-	-	-	-
Ending balance	302,971	792,936	-	-	-	-	-
MBTUs per ton burned	-	25.14	-	-	-	-	-
Cost of ending inventory ($/ton)	85.10	78.02	-	-	-	-	-
Oil Data:							
Beginning balance	215,268	405,193	4,105,852	6,659,501	2,450,460	-	723,104
Gallons received during period	90,248	246,781	372,704	-	-	-	-
Miscellaneous use and adjustments	(3,801)	(7,517)	-	-	-	-	-
Gallons burned during period	-	301,964	385	-	-	-	-
Ending balance	301,715	342,493	4,478,171	6,659,501	2,450,460	-	723,104
Cost of ending inventory ($/gal)	1.73	1.68	2.15	2.33	2.80	-	2.37
Natural Gas Data:							
Beginning balance	-	-	-	-	-	-	-
MCF received during period	-	-	2,229,642	4,952,919	2,637,398	707,132	-
MCF burned during period	-	-	2,229,642	4,952,919	2,637,398	707,132	-
Ending balance	-	-	-	-	-	-	-
Biogas Data:							
Beginning balance	-	-	-	-	-	-	-
MCF received during period	-	-	-	10,507	-	-	-
MCF burned during period	-	-	-	10,507	-	-	-
Ending balance	-	-	-	-	-	-	-
Limestone/Lime Data:							
Beginning balance	19,554	65,526		-	-		-
Tons received during period	1,184	14,190		-	-		-
Inventory adjustments	-	-		-	-		-
Tons consumed during period	-	7,485		-	-		-
Ending balance	20,738	72,231		-	-		-
Cost of ending inventory ($/ton)	37.24	44.95		-	-		-

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
MARCH 2021

Description	Darlington	Wayne County	Weatherspoon	Brunswick	Harris	Robinson	Current Month	Total 12 ME March 2021
Coal Data:								
Beginning balance	-	-	-	-	-	-	970,411	1,756,444
Tons received during period	-	-	-	-	-	-	270,768	2,629,013
Inventory adjustments	-	-	-	-	-	-	-	132,593
Tons burned during period	-	-	-	-	-	-	145,272	3,422,143
Ending balance	-	-	-	-	-	-	1,095,907	1,095,907
MBTUs per ton burned	-	-	-	-	-	-	25.14	25.03
Cost of ending inventory ($/ton)	-	-	-	-	-	-	79.98	79.98
Oil Data:								
Beginning balance	9,877,836	9,631,997	470,014	117,269	250,015	14,794	34,921,303	39,159,009
Gallons received during period	-	-	-	-	-	-	709,733	3,336,887
Miscellaneous use and adjustments	-	-	-	-	-	-	(11,318)	(141,133)
Gallons burned during period	14,709	661	13,249	-	-	-	330,968	7,066,013
Ending balance	9,863,127	9,631,336	456,765	117,269	250,015	14,794	35,288,750	35,288,750
Cost of ending inventory ($/gal)	2.39	2.40	2.23	2.31	2.31	2.31	2.36	2.36
Natural Gas Data:								
Beginning balance	-	-	-	-	-	-	-	-
MCF received during period	516	772,390	-	-	-	-	11,299,997	152,259,346
MCF burned during period	516	772,390	-	-	-	-	11,299,997	152,259,346
Ending balance	-	-	-	-	-	-	-	-
Biogas Data:								
Beginning balance	-	-	-	-	-	-	-	-
MCF received during period	-	-	-	-	-	-	10,507	159,548
MCF burned during period	-	-	-	-	-	-	10,507	159,548
Ending balance	-	-	-	-	-	-	-	-
Limestone/Lime Data:								
Beginning balance	-	-	-	-	-	-	85,080	136,055
Tons received during period	-	-	-	-	-	-	15,374	124,598
Inventory adjustments	-	-	-	-	-	-	-	7,807
Tons consumed during period	-	-	-	-	-	-	7,485	175,491
Ending balance	-	-	-	-	-	-	92,969	92,969
Cost of ending inventory ($/ton)	-	-	-	-	-	-	43.23	43.23

Schedule 7

DUKE ENERGY PROGRESS

ANALYSIS OF COAL PURCHASED

MARCH 2021

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
MAYO	SPOT	-	-	-
	CONTRACT	24,237	$ 1,791,177	73.90
	FIXED TRANSPORTATION/ADJUSTMENTS	-	270,717	-
	TOTAL	24,237	$ 2,061,894	85.07
ROXBORO	SPOT	49,040	$ 2,481,882	$ 50.61
	CONTRACT	197,491	12,396,010	62.77
	FIXED TRANSPORTATION/ADJUSTMENTS	-	654,951	-
	TOTAL	246,531	$ 15,532,843	$ 63.01
ALL PLANTS	SPOT	49,040	$ 2,481,882	$ 50.61
	CONTRACT	221,728	14,187,187	63.98
	FIXED TRANSPORTATION/ADJUSTMENTS	-	925,668	-
	TOTAL	270,768	$ 17,594,737	$ 64.98

Schedule 8

DUKE ENERGY PROGRESS

ANALYSIS OF COAL QUALITY RECEIVED

MARCH 2021

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
MAYO	9.18	9.76	12,047	1.91
ROXBORO	6.96	9.27	12,628	1.83

Schedule 9

DUKE ENERGY PROGRESS

ANALYSIS OF OIL PURCHASED

MARCH 2021

	ASHEVILLE CC	MAYO	ROXBORO
VENDOR	Indigo and Charlotte Tank Farm	Greensboro Tank Farm	Indigo and Greensboro Tank Farm
SPOT/CONTRACT	Contract	Contract	Contract
SULFUR CONTENT %	0	0	0
GALLONS RECEIVED	372,704	90,248	246,781
TOTAL DELIVERED COST	$ 1,041,674	$ 170,537	$ 480,943
DELIVERED COST/GALLON	$ 2.79	$ 1.89	$ 1.95
BTU/GALLON	138,000	138,000	138,000

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2020 - March, 2021
Nuclear Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Brunswick 1	7,603,327	938	92.53	90.59
Brunswick 2	7,431,921	932	91.03	91.20
Harris 1	8,310,706	964	98.41	96.36
Robinson 2	6,099,247	759	91.73	90.54

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2020 through March, 2021
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Lee Energy Complex	1A	979,160	225	49.68	67.24
Lee Energy Complex	1B	837,672	227	42.13	58.64
Lee Energy Complex	1C	1,055,170	228	52.83	70.84
Lee Energy Complex	ST1	1,977,757	379	59.57	80.21
Lee Energy Complex	Block Total	4,849,759	1,059	52.28	70.81
Smith Energy Complex	7	922,894	194	54.37	76.44
Smith Energy Complex	8	905,445	194	53.35	75.54
Smith Energy Complex	ST4	1,061,249	183	66.38	83.06
Smith Energy Complex	9	1,392,331	216	73.67	87.72
Smith Energy Complex	10	1,407,174	216	74.45	87.67
Smith Energy Complex	ST5	1,812,581	249	83.10	98.31
Smith Energy Complex	Block Total	7,501,674	1,251	68.48	85.50
Sutton Energy Complex	1A	1,220,734	224	62.21	77.94
Sutton Energy Complex	1B	1,230,177	224	62.69	78.25
Sutton Energy Complex	ST1	1,523,507	271	64.18	88.39
Sutton Energy Complex	Block Total	3,974,418	719	63.10	81.98
Asheville CC	ACC CT5	1,094,763	191	65.61	78.56
Asheville CC	ACC CT7	1,175,222	191	70.43	77.52
Asheville CC	ACC ST6	526,336	90	66.76	71.38
Asheville CC	ACC ST8	559,307	90	70.94	76.08
Asheville CC	Block Total	3,355,628	561	68.28	76.68

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, 2020 through March, 2021

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Mayo 1	1,089,938	738	16.86	43.59
Roxboro 2	2,161,855	673	36.67	65.87
Roxboro 3	2,082,153	698	34.05	72.50
Roxboro 4	1,311,211	711	21.05	56.49

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, 2020 through March, 2021
Other Cycling Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Roxboro 1	841,199	380	25.27	77.41

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, 2020 through March, 2021
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Asheville CT	130,643	351	92.03
Blewett CT	-205	68	86.03
Darlington CT	1,934	266	87.36
Smith Energy Complex CT	1,065,170	941	86.70
Sutton Fast Start CT	37,702	98	96.69
Wayne County CT	255,594	962	94.53
Weatherspoon CT	110	164	98.89

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, 2020 through March, 2021
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Blewett	65,541	27.0	35.35
Marshall	-228	4.0	41.96
Tillery	329,014	84.3	92.07
Walters	525,016	113.0	63.45

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

Period: March, 2021

Station	Unit	Date of Outage	Duration of Outage	Scheduled / Unscheduled	Cause of Outage	Reason Outage Occurred	Remedial Action Taken
Brunswick	1	None					
	2	03/05/2021 - 04/01/2021	625.65	Scheduled	B2R25 Refueling Outage.	Scheduled B2R25 refuelling outage.	None
Harris	1	None					
Robinson	2	None					

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2021

DEP Asheville CC

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
ACC CT7	3/1/2021 4:53:00 AM To 3/1/2021 8:00:00 AM	Unsch	5299	Other Gas Turbine Problems	Water Wash drain valve failed and is blowing through during startup. Unit shut down.	
ACC CT7	3/1/2021 9:17:00 PM To 3/2/2021 4:39:00 PM	Unsch	5108	Gas Turbine - High Engine Exhaust Temperature	High Exhaust Thermocouple trip.	
ACC ST8	3/1/2021 9:17:00 PM To 3/2/2021 4:39:00 PM	Sch	5109	Other Gas Turbine Exhaust Problems	High exhaust thermocouple temperatures tripped gas turbine.	

Lee Energy Complex

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
1A	3/10/2021 10:54:00 AM To 4/1/2021 12:00:00 AM	Sch	5082	Gas Turbine - High Pressure Blades/buckets	GMS Outage for Turbine Major.	
1B	1/9/2021 6:57:00 AM To 4/7/2021 5:51:00 PM	Unsch	5285	Gas Turbine Vibration	01B tripped after turbine/generator vibration and subsequent damage.	
1C	3/6/2021 1:44:00 AM To 4/1/2021 12:00:00 AM	Sch	5082	Gas Turbine - High Pressure Blades/buckets	GMS Outage for CT Major.	
ST1	3/10/2021 10:13:00 AM To 4/1/2021 12:00:00 AM	Sch	4261	Turbine Control Valves	GMS outage for valve replacement and other work.	

Mayo Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
1	2/27/2021 12:02:00 AM To 3/13/2021 12:00:00 AM	Sch	3611	Switchyard Circuit Breakers	Planned outage for switch yard work by Transmission.	
1	3/13/2021 12:00:00 AM To 3/27/2021 12:00:00 AM	Sch	0105	Bunker Structures	Outage extended to repair surge bin chutes.	
1	3/27/2021 12:00:00 AM To 4/1/2021 12:00:00 AM	Sch	3619	Other Switchyard Equipment	Switch yard work being performed by Transmission.	

Roxboro Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
3	2/21/2021 7:42:00 PM To 3/3/2021 3:00:00 PM	Sch	8816	SCR Plugging	Clean 3A & 3B SCRs.	
4	3/7/2021 4:26:00 PM To 3/12/2021 5:00:00 PM	Unsch	1050	Second Superheater Leaks	Tube leaks in both boilers.	
4	3/12/2021 5:00:00 PM To 3/18/2021 1:00:00 PM	Sch	1470	Induced Draft Fan Motors and Drives	4B1 Induced Draft fan repairs.	
4	3/27/2021 12:00:00 AM To 4/1/2021 12:00:00 AM	Sch	1800	Major Boiler Overhaul (720 Hours or Longer)	Planned outage.	

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
March 2021

Smith Energy Complex

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
7	3/6/2021 1:16:00 AM To 3/14/2021 10:07:00 PM	Sch	5035	Compressor Washing	Power Block 4 Spring GMS outage.	
7	3/26/2021 5:55:00 AM To 3/26/2021 12:43:00 PM	Unsch	9020	Lightning	PB4 tripped due to lightning.	
8	3/1/2021 5:14:00 AM To 3/1/2021 9:12:00 AM	Unsch	5299	Other Gas Turbine Problems	High Haz Gas trip due to leaking packing on gas control valves.	
8	3/6/2021 1:16:00 AM To 3/14/2021 8:55:00 PM	Sch	5035	Compressor Washing	Power Block 4 Spring GMS outage.	
8	3/15/2021 1:30:00 PM To 3/15/2021 8:20:00 PM	Unsch	0590	Desuperheater/Attemperator Valves	Air solenoid failed to ReHeat attempt spray water Automtatic Block Valve.	
8	3/26/2021 5:55:00 AM To 3/26/2021 1:04:00 PM	Unsch	9020	Lightning	PB4 tripped due to lightning.	
ST4	3/6/2021 12:24:00 AM To 3/15/2021 1:20:00 AM	Sch	5035	Compressor Washing	Power Block 4 Spring GMS outage.	
ST4	3/26/2021 5:55:00 AM To 3/26/2021 2:21:00 PM	Unsch	9020	Lightning	PB4 tripped due to lightning.	
9	3/2/2021 5:01:00 AM To 3/4/2021 4:29:00 PM	Unsch	5075	Blade Path Temperature Spread	Unit removed from service due to low load demand. High Blade Path Spreads tripped the unit on startup.	
9	3/4/2021 4:35:00 PM To 3/5/2021 9:03:00 PM	Unsch	5075	Blade Path Temperature Spread	Unit removed from service due to low load demand. High Blade Path Spreads tripped the unit on startup.	
9	3/5/2021 11:07:00 PM To 3/6/2021 2:26:00 PM	Unsch	4899	Other Miscellaneous Generator Problems	Unit tripped to reverse power relay.	
9	3/6/2021 6:16:00 PM To 3/6/2021 10:28:00 PM	Unsch	5075	Blade Path Temperature Spread	Unit removed from service due to low load demand. High Blade Path Spreads tripped the unit on startup.	

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.

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2021
Brunswick Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	938		932	
(B) Period Hours	743		743	
(C) Net Gen (mWh) and Capacity Factor (%)	717,239	102.91	98,065	14.16
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00	583,106	84.21
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00	11,305	1.63
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-20,305	-2.91	0	0.00
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00
(J) Net mWh Possible in Period	696,934	100.00%	692,476	100.00%
(K) Equivalent Availability (%)		100.00		15.28
(L) Output Factor (%)		102.91		89.66
(M) Heat Rate (BTU/NkWh)		10,292		11,514

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2021
Harris Nuclear Station

	Unit 1	
(A) MDC (mW)	964	
(B) Period Hours	743	
(C) Net Gen (mWh) and Capacity Factor (%)	740,789	103.43
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-24,537	-3.43
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	716,252	100.00%
(K) Equivalent Availability (%)		100.00
(L) Output Factor (%)		103.43
(M) Heat Rate (BTU/NkWh)		10,086

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2021
Robinson Nuclear Station

	Unit 2	
(A) MDC (mW)	759	
(B) Period Hours	743	
(C) Net Gen (mWh) and Capacity Factor (%)	581,871	103.18
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-17,934	-3.18
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	563,937	100.00%
(K) Equivalent Availability (%)		100.00
(L) Output Factor (%)		103.18
(M) Heat Rate (BTU/NkWh)		10,192

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2021

DEP Asheville CC

	ACC CT5	ACC ST6	Block Total
(A) MDC (mW)	192	90	282
(B) Period Hrs	743	743	743
(C) Net Generation (mWh)	130,807	67,522	198,329
(D) Capacity Factor (%)	91.69	100.98	94.66
(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	14,489	1,857	16,346
(H) Scheduled Derates: percent of Period Hrs	10.16	2.78	7.80
(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	142,656	66,870	209,526
(P) Equivalent Availability (%)	89.84	97.22	92.20
(Q) Output Factor (%)	91.69	100.98	94.66
(R) Heat Rate (BTU/NkWh)	9,581	0	6,319

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2021

DEP Asheville CC

	ACC CT7	ACC ST8	Block Total
(A) MDC (mW)	192	90	282
(B) Period Hrs	743	743	743
(C) Net Generation (mWh)	97,391	50,271	147,662
(D) Capacity Factor (%)	68.27	75.18	70.47
(E) Net mWh Not Generated due to Full Scheduled Outages	0	1,743	1,743
(F) Scheduled Outages: percent of Period Hrs	0.00	2.61	0.83
(G) Net mWh Not Generated due to Partial Scheduled Outages	14,050	1,809	15,859
(H) Scheduled Derates: percent of Period Hrs	9.85	2.71	7.57
(I) Net mWh Not Generated due to Full Forced Outages	4,317	0	4,317
(J) Forced Outages: percent of Period Hrs	3.03	0.00	2.06
(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	26,898	13,047	39,945
(N) Economic Dispatch: percent of Period Hrs	18.86	19.51	19.06
(O) Net mWh Possible in Period	142,656	66,870	209,526
(P) Equivalent Availability (%)	87.13	94.69	89.54
(Q) Output Factor (%)	86.70	96.04	89.67
(R) Heat Rate (BTU/NkWh)	10,111	0	6,669

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2021

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)	43,919	-765	21,421	40,344	104,919
(D) Capacity Factor (%)	26.27	0.00	12.64	14.33	13.33
(E) Net mWh Not Generated due to Full Scheduled Outages	116,122	0	141,649	195,861	453,632
(F) Scheduled Outages: percent of Period Hrs	69.46	0.00	83.62	69.55	57.65
(G) Net mWh Not Generated due to Partial Scheduled Outages	6,240	0	3,530	113	9,883
(H) Scheduled Derates: percent of Period Hrs	3.73	0.00	2.08	0.04	1.26
(I) Net mWh Not Generated due to Full Forced Outages	0	168,661	0	0	168,661
(J) Forced Outages: percent of Period Hrs	0.00	100.00	0.00	0.00	21.44
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	21,151	21,151
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	7.51	2.69
(M) Net mWh Not Generated due to Economic Dispatch	894	0	2,804	24,128	27,826
(N) Economic Dispatch: percent of Period Hrs	0.53	0.00	1.66	8.57	3.54
(O) Net mWh Possible in Period	167,175	168,661	169,404	281,597	786,837
(P) Equivalent Availability (%)	26.81	0.00	14.30	22.90	16.97
(Q) Output Factor (%)	86.03	0.00	77.18	47.06	63.76
(R) Heat Rate (BTU/NkWh)	8,468	0	8,543	4,421	6,989

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2021

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)	70,623	68,062	80,613	219,298
(D) Capacity Factor (%)	49.25	47.46	58.97	51.78
(E) Net mWh Not Generated due to Full Scheduled Outages	40,887	40,655	39,732	121,274
(F) Scheduled Outages: percent of Period Hrs	28.51	28.35	29.06	28.64
(G) Net mWh Not Generated due to Partial Scheduled Outages	10,749	10,545	3,371	24,665
(H) Scheduled Derates: percent of Period Hrs	7.50	7.35	2.47	5.82
(I) Net mWh Not Generated due to Full Forced Outages	1,312	3,464	1,552	6,328
(J) Forced Outages: percent of Period Hrs	0.92	2.42	1.14	1.49
(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	19,827	20,672	11,444	51,944
(N) Economic Dispatch: percent of Period Hrs	13.83	14.42	8.37	12.27
(O) Net mWh Possible in Period	143,399	143,399	136,712	423,510
(P) Equivalent Availability (%)	63.08	61.88	67.34	64.05
(Q) Output Factor (%)	73.58	72.89	86.81	77.71
(R) Heat Rate (BTU/NkWh)	14,022	1,418	0	4,956

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2021

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)	101,455	121,206	138,357	361,018
(D) Capacity Factor (%)	63.51	75.87	73.89	71.25
(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	11,758	13,745	0	25,503
(H) Scheduled Derates: percent of Period Hrs	7.36	8.60	0.00	5.03
(I) Net mWh Not Generated due to Full Forced Outages	23,102	0	0	23,102
(J) Forced Outages: percent of Period Hrs	14.46	0.00	0.00	4.56
(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	23,431	24,794	48,879	97,103
(N) Economic Dispatch: percent of Period Hrs	14.67	15.52	26.11	19.16
(O) Net mWh Possible in Period	159,745	159,745	187,236	506,726
(P) Equivalent Availability (%)	78.18	91.40	100.00	90.41
(Q) Output Factor (%)	79.50	81.23	78.73	79.77
(R) Heat Rate (BTU/NkWh)	13,651	13,492	0	8,366

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2021

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)	117,265	120,047	138,214	375,526
(D) Capacity Factor (%)	70.46	72.13	68.64	70.29
(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	4,252	44,002
(H) Scheduled Derates: percent of Period Hrs	12.05	11.83	2.11	8.24
(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	802	802
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.40	0.15
(M) Net mWh Not Generated due to Economic Dispatch	29,106	26,696	58,085	113,887
(N) Economic Dispatch: percent of Period Hrs	17.49	16.04	28.85	21.32
(O) Net mWh Possible in Period	166,432	166,432	201,353	534,217
(P) Equivalent Availability (%)	87.95	88.17	97.49	91.61
(Q) Output Factor (%)	72.09	72.49	68.64	70.90
(R) Heat Rate (BTU/NkWh)	11,441	11,441	0	7,230

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

Duke Energy Progress
Intermediate Power Plant Performance
Review Plan
March 2021

		Mayo Station
		Unit 1
(A)	**MDC (mW)**	713
(B)	**Period Hrs**	743
(C)	**Net Generation (mWh)**	-6,496
(D)	**Net mWh Possible in Period**	529,759
(E)	**Equivalent Availability (%)**	0.00
(F)	**Output Factor (%)**	0.00
(G)	**Capacity Factor (%)**	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
Intermediate Power Plant Performance
Review Plan
March 2021

Roxboro Station

		Unit 2	Unit 3	Unit 4
(A)	**MDC (mW)**	673	698	711
(B)	**Period Hrs**	743	743	743
(C)	**Net Generation (mWh)**	-2,161	240,582	61,300
(D)	**Net mWh Possible in Period**	500,039	518,614	528,273
(E)	**Equivalent Availability (%)**	100.00	90.46	38.58
(F)	**Output Factor (%)**	0.00	54.91	40.60
(G)	**Capacity Factor (%)**	0.00	46.39	11.60

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

April 2020 - March 2021
Brunswick Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	938		932	
(B) Period Hours	8760		8760	
(C) Net Gen (mWh) and Capacity Factor (%)	7,603,327	92.53	7,431,921	91.03
(D) Net mWh Not Gen due to Full Schedule Outages	226,543	2.76	583,106	7.14
* (E) Net mWh Not Gen due to Partial Scheduled Outages	42,711	0.52	36,880	0.45
(F) Net mWh Not Gen due to Full Forced Outages	411,032	5.00	40,449	0.50
* (G) Net mWh Not Gen due to Partial Forced Outages	-66,733	-0.81	71,964	0.88
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00
(J) Net mWh Possible in Period	8,216,880	100.00%	8,164,320	100.00%
(K) Equivalent Availability (%)		90.59		91.20
(L) Output Factor (%)		100.32		98.56
(M) Heat Rate (BTU/NkWh)		10,384		10,723

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2020 - March 2021
Harris Nuclear Station

	Unit 1	
(A) MDC (mW)	964	
(B) Period Hours	8760	
(C) Net Gen (mWh) and Capacity Factor (%)	8,310,706	98.41
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	80,324	0.95
(F) Net mWh Not Gen due to Full Forced Outages	202,633	2.40
* (G) Net mWh Not Gen due to Partial Forced Outages	-149,023	-1.76
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	8,444,640	100.00%
(K) Equivalent Availability (%)		96.36
(L) Output Factor (%)		100.83
(M) Heat Rate (BTU/NkWh)		10,231

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2020 - March 2021
Robinson Nuclear Station

	Unit 2	
(A) MDC (mW)	759	
(B) Period Hours	8760	
(C) Net Gen (mWh) and Capacity Factor (%)	6,099,247	91.73
(D) Net mWh Not Gen due to Full Schedule Outages	582,912	8.77
* (E) Net mWh Not Gen due to Partial Scheduled Outages	80,855	1.22
(F) Net mWh Not Gen due to Full Forced Outages	11,752	0.18
* (G) Net mWh Not Gen due to Partial Forced Outages	-125,926	-1.90
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	6,648,840	100.00%
(K) Equivalent Availability (%)		90.54
(L) Output Factor (%)		100.74
(M) Heat Rate (BTU/NkWh)		10,282

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2020 through March, 2021

DEP Asheville CC

	ACC CT5	ACC ST6	Block Total
(A) MDC (mW)	191	90	281
(B) Period Hrs	8,760	8,760	8,760
(C) Net Generation (mWh)	1,094,763	526,336	1,621,099
(D) Capacity Factor (%)	65.61	66.76	65.98
(E) Net mWh Not Generated due to Full Scheduled Outages	177,074	182,217	359,291
(F) Scheduled Outages: percent of Period Hrs	10.61	23.11	14.62
(G) Net mWh Not Generated due to Partial Scheduled Outages	162,806	20,871	183,677
(H) Scheduled Derates: percent of Period Hrs	9.76	2.65	7.48
(I) Net mWh Not Generated due to Full Forced Outages	16,815	22,592	39,406
(J) Forced Outages: percent of Period Hrs	1.01	2.87	1.60
(K) Net mWh Not Generated due to Partial Forced Outages	284	0	284
(L) Forced Derates: percent of Period Hrs	0.02	0.00	0.01
(M) Net mWh Not Generated due to Economic Dispatch	216,976	36,385	253,360
(N) Economic Dispatch: percent of Period Hrs	13.00	4.61	10.31
(O) Net mWh Possible in Period	1,668,718	788,400	2,457,118
(P) Equivalent Availability (%)	78.56	71.38	76.29
(Q) Output Factor (%)	87.99	95.89	90.41
(R) Heat Rate (BTU/NkWh)	9,999	0	6,753

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2020 through March, 2021

DEP Asheville CC

	ACC CT7	ACC ST8	Block Total
(A) MDC (mW)	191	90	281
(B) Period Hrs	8,760	8,760	8,760
(C) Net Generation (mWh)	1,175,222	559,307	1,734,529
(D) Capacity Factor (%)	70.43	70.94	70.59
(E) Net mWh Not Generated due to Full Scheduled Outages	193,787	136,195	329,983
(F) Scheduled Outages: percent of Period Hrs	11.61	17.27	13.43
(G) Net mWh Not Generated due to Partial Scheduled Outages	165,352	23,820	189,172
(H) Scheduled Derates: percent of Period Hrs	9.91	3.02	7.70
(I) Net mWh Not Generated due to Full Forced Outages	15,419	28,594	44,014
(J) Forced Outages: percent of Period Hrs	0.92	3.63	1.79
(K) Net mWh Not Generated due to Partial Forced Outages	7	0	7
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	118,930	40,483	159,413
(N) Economic Dispatch: percent of Period Hrs	7.13	5.13	6.49
(O) Net mWh Possible in Period	1,668,718	788,400	2,457,118
(P) Equivalent Availability (%)	77.52	76.08	77.08
(Q) Output Factor (%)	85.53	95.05	88.39
(R) Heat Rate (BTU/NkWh)	9,927	0	6,726

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2020 through March, 2021

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)	979,160	837,672	1,055,170	1,977,757	4,849,759
(D) Capacity Factor (%)	49.68	42.13	52.83	59.57	52.28
(E) Net mWh Not Generated due to Full Scheduled Outages	267,919	126,420	309,259	424,196	1,127,794
(F) Scheduled Outages: percent of Period Hrs	13.59	6.36	15.48	12.78	12.16
(G) Net mWh Not Generated due to Partial Scheduled Outages	230,492	249,292	250,796	27,760	758,340
(H) Scheduled Derates: percent of Period Hrs	11.69	12.54	12.56	0.84	8.17
(I) Net mWh Not Generated due to Full Forced Outages	147,304	446,755	22,382	1,068	617,508
(J) Forced Outages: percent of Period Hrs	7.47	22.47	1.12	0.03	6.66
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	203,925	203,925
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	6.14	2.20
(M) Net mWh Not Generated due to Economic Dispatch	346,125	325,632	359,672	685,335	1,716,765
(N) Economic Dispatch: percent of Period Hrs	17.56	16.51	18.01	20.64	18.51
(O) Net mWh Possible in Period	1,971,000	1,988,520	1,997,280	3,320,040	9,276,840
(P) Equivalent Availability (%)	67.24	58.64	70.84	80.21	70.81
(Q) Output Factor (%)	64.76	61.28	64.89	69.97	66.15
(R) Heat Rate (BTU/NkWh)	10,131	10,507	10,101	3,469	7,473

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2020 through March, 2021

Smith Energy Complex

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	194	194	183	570
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	922,894	905,445	1,061,249	2,889,588
(D) Capacity Factor (%)	54.37	53.35	66.38	57.87
(E) Net mWh Not Generated due to Full Scheduled Outages	218,077	181,858	172,210	572,145
(F) Scheduled Outages: percent of Period Hrs	12.85	10.71	10.77	11.46
(G) Net mWh Not Generated due to Partial Scheduled Outages	180,705	180,651	73,571	434,927
(H) Scheduled Derates: percent of Period Hrs	10.65	10.64	4.60	8.71
(I) Net mWh Not Generated due to Full Forced Outages	1,312	52,892	4,109	58,314
(J) Forced Outages: percent of Period Hrs	0.08	3.12	0.26	1.17
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	20,686	20,686
(L) Forced Derates: percent of Period Hrs	0.00	0.00	1.29	0.41
(M) Net mWh Not Generated due to Economic Dispatch	373,737	375,877	266,814	1,016,428
(N) Economic Dispatch: percent of Period Hrs	22.05	22.18	16.69	20.36
(O) Net mWh Possible in Period	1,697,281	1,697,281	1,598,638	4,993,200
(P) Equivalent Availability (%)	76.44	75.54	83.06	78.25
(Q) Output Factor (%)	75.69	75.16	87.50	79.45
(R) Heat Rate (BTU/NkWh)	11,807	10,920	0	7,193

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2020 through March, 2021

Smith Energy Complex

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	216	216	249	681
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,392,331	1,407,174	1,812,581	4,612,086
(D) Capacity Factor (%)	73.67	74.45	83.10	77.37
(E) Net mWh Not Generated due to Full Scheduled Outages	25,546	48,528	30,314	104,387
(F) Scheduled Outages: percent of Period Hrs	1.35	2.57	1.39	1.75
(G) Net mWh Not Generated due to Partial Scheduled Outages	180,946	181,055	3,257	365,258
(H) Scheduled Derates: percent of Period Hrs	9.57	9.58	0.15	6.13
(I) Net mWh Not Generated due to Full Forced Outages	25,616	3,564	2,449	31,628
(J) Forced Outages: percent of Period Hrs	1.36	0.19	0.11	0.53
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	710	710
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.03	0.01
(M) Net mWh Not Generated due to Economic Dispatch	265,562	249,680	331,805	847,047
(N) Economic Dispatch: percent of Period Hrs	14.05	13.21	15.21	14.21
(O) Net mWh Possible in Period	1,890,001	1,890,001	2,181,116	5,961,118
(P) Equivalent Availability (%)	87.72	87.67	98.31	91.58
(Q) Output Factor (%)	80.12	79.89	89.33	83.43
(R) Heat Rate (BTU/NkWh)	11,730	11,582	0	7,075

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2020 through March, 2021

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)	1,220,734	1,230,177	1,523,507	3,974,418
(D) Capacity Factor (%)	62.21	62.69	64.18	63.10
(E) Net mWh Not Generated due to Full Scheduled Outages	186,387	187,268	225,571	599,226
(F) Scheduled Outages: percent of Period Hrs	9.50	9.54	9.50	9.51
(G) Net mWh Not Generated due to Partial Scheduled Outages	244,076	239,454	43,822	527,352
(H) Scheduled Derates: percent of Period Hrs	12.44	12.20	1.85	8.37
(I) Net mWh Not Generated due to Full Forced Outages	2,352	0	0	2,352
(J) Forced Outages: percent of Period Hrs	0.12	0.00	0.00	0.04
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	6,231	6,231
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.26	0.10
(M) Net mWh Not Generated due to Economic Dispatch	308,692	305,342	574,828	1,188,861
(N) Economic Dispatch: percent of Period Hrs	15.73	15.56	24.21	18.88
(O) Net mWh Possible in Period	1,962,240	1,962,240	2,373,960	6,298,440
(P) Equivalent Availability (%)	77.94	78.25	88.39	81.98
(Q) Output Factor (%)	71.01	71.21	72.76	71.73
(R) Heat Rate (BTU/NkWh)	11,680	11,679	0	7,202

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

Duke Energy Progress
Intermediate Power Plant
Performance Review Plan
April, 2020 through March, 2021

Mayo Station

Units	Unit 1
(A) MDC (mW)	738
(B) Period Hrs	8,760
(C) Net Generation (mWh)	1,089,938
(D) Net mWh Possible in Period	6,463,713
(E) Equivalent Availability (%)	43.59
(F) Output Factor (%)	44.97
(G) Capacity Factor (%)	16.86

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, 2020 through March, 2021

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)	2,161,855	2,082,153	1,311,211
(D) Net mWh Possible in Period	5,895,480	6,114,480	6,228,360
(E) Equivalent Availability (%)	65.87	72.50	56.49
(F) Output Factor (%)	68.97	62.37	63.16
(G) Capacity Factor (%)	36.67	34.05	21.05

Notes:

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

Duke Energy Progress
Outages for 100 mW or Larger Units
March, 2021

Unit Name	Capacity Rating (mW)	Full Outage Hours Scheduled	Full Outage Hours Unscheduled	Total
Brunswick 1	938	0.00	0.00	0.00
Brunswick 2	932	625.65	0.00	625.65
Harris 1	964	0.00	0.00	0.00
Robinson 2	759	0.00	0.00	0.00

Duke Energy Progress
Outages for 100 mW or Larger Units
March 2021

Unit Name	Capacity Rating (mW)	Full Outage Hours Scheduled	Full Outage Hours Unscheduled	Total Outage Hours
ACC CT5	192	0.00	0.00	0.00
ACC CT7	192	0.00	22.48	22.48
ACC ST6	90	0.00	0.00	0.00
ACC ST8	90	19.37	0.00	19.37

Notes:

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

Duke Energy Progress
Outages for 100 mW or Larger Units
March 2021

Unit Name	Capacity Rating (mW)	Full Outage Hours Scheduled	Full Outage Hours Unscheduled	Total Outage Hours
Asheville CT 3	185	0.00	0.00	0.00
Asheville CT 4	185	24.25	0.00	24.25
Darlington CT 12	131	49.00	0.00	49.00
Darlington CT 13	133	185.00	0.00	185.00
Lee Energy Complex CC 1A	225	516.10	0.00	516.10
Lee Energy Complex CC 1B	227	0.00	743.00	743.00
Lee Energy Complex CC 1C	228	621.27	0.00	621.27
Lee Energy Complex CC ST1	379	516.78	0.00	516.78
Mayo Steam 1	713	743.00	0.00	743.00
Smith Energy Complex CT 1	192	0.00	486.93	486.93
Smith Energy Complex CT 2	192	66.00	0.00	66.00
Smith Energy Complex CT 3	192	309.00	0.00	309.00
Smith Energy Complex CT 4	192	0.00	0.00	0.00
Smith Energy Complex CT 6	192	0.00	0.68	0.68
Smith Energy Complex CC 7	193	211.85	6.80	218.65
Smith Energy Complex CC 8	193	210.65	17.95	228.60
Smith Energy Complex CC ST4	184	215.93	8.43	224.37
Smith Energy Complex CC 9	215	0.00	107.45	107.45
Smith Energy Complex CC 10	215	0.00	0.00	0.00
Smith Energy Complex CC ST5	252	0.00	0.00	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
Outages for 100 mW or Larger Units
March 2021

Unit Name	Capacity Rating (mW)	Full Outage Hours Scheduled	Full Outage Hours Unscheduled	Total Outage Hours
Roxboro Steam 1	380	0.00	0.00	0.00
Roxboro Steam 2	673	0.00	0.00	0.00
Roxboro Steam 3	698	63.00	0.00	63.00
Roxboro Steam 4	711	259.00	120.57	379.57
Sutton Energy Complex CC 1A	224	0.00	0.00	0.00
Sutton Energy Complex CC 1B	224	0.00	0.00	0.00
Sutton Energy Complex CC ST1	271	0.00	0.00	0.00
Wayne County CT 10	187	0.00	0.00	0.00
Wayne County CT 11	192	0.00	0.00	0.00
Wayne County CT 12	193	0.00	0.00	0.00
Wayne County CT 13	191	0.00	0.00	0.00
Wayne County CT 14	195	0.00	0.00	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, LLC
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Harrington Workpaper 1

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs	7,325,424	8,001,034	7,708,915	6,301,643	29,337,015
Hours in Year	7,969	8,760	8,160	8,472	8,760
MDC	938	932	964	759	3,593
Cost	$ 46,548,110	$ 46,679,832	$ 43,623,328	$ 35,371,888	$ 172,223,158
$/MWhs	$ 6.35	$ 5.83	$ 5.66	$ 5.61	
Avg. $/MWhs					**$ 5.8705**
Cents per kWh					**0.5871**

	GWhs	Capacity Rating MDC	Hours	Proposed Nuclear Capacity Factor
Brunswick 1	7,325	938	7,969	98.00%
Brunswick 2	8,001	932	8,760	98.00%
Harris 1	7,709	964	8,160	98.00%
Robinson 1	6,302	759	8,472	98.00%
	29,337	3,593	8,760	**93.21%**

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, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs with NERC applied	7,083,984	7,737,326	7,299,871	5,771,148	27,892,328
Hours in Year	7,969	8,760	8,160	8,472	8,760
MDC	938	932	964	759	3,593
Capacity Factor-NERC 5yr Avg	0.9477	0.9477	0.9280	0.8975	
Cost ($)	$ 41,586,576	$ 45,422,028	$ 42,853,943	$ 33,879,563	$ 163,742,110
$/MWhs	$ 5.87	$ 5.87	$ 5.87	$ 5.87	
Avg. $/MWHs					**$ 5.87**
Cents per kWh					**0.5871**

	Capacity Rating MDC	NCF Rating	Weighted Average
Brunswick 1	938	94.77%	24.74%
Brunswick 2	932	94.77%	24.58%
Harris 1	964	92.80%	24.90%
Robinson 1	759	89.75%	18.96%
	3,593		**93.18%**

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, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Resource Type		**MWh Dec'21-Nov'22**
Nuclear		29,348,553
Adjust for Lower Nuclear Capacity Factor		(11,538)
Adjusted Nuclear Total		29,337,015
Coal		7,506,813
Adjust for Lower Nuclear Capacity Factor		11,538
Adjusted Coal Total		7,518,351
Gas CT and CC Total		21,918,020
Total Hydro		647,824
Utility Owned Solar Generation		265,105
Total Net Generation		59,686,315
Purchases for REPS Compliance	2,065,380	
Purchases from Qualifying Facilities	4,885,514	
Purchases from Dispatchable Units	1,842,196	
Emergency & DSM Purchases	2,941	
Allocated Economic Purchases	281,010	
Joint Dispatch Fuel Transfer Purchases	1,087,546	10,164,587
Total Net Generation and Purchases		69,850,902
Sales Totals (intersystem sales)	(120,919)	
Fuel Transfer Sales (JDA & economic sales)	(5,456,324)	(5,577,243)
Line Losses and Company Use		(2,310,113)
Total NC System Sales		**61,963,546**

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, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Resource Type		**Costs $ Dec'21-Nov'22**
Nuclear		$ 172,307,153
Adjust for Lower Nuclear Capacity Factor		(83,994)
Adjusted Nuclear		172,223,158
Coal		204,377,419
Adjust for Lower Nuclear Capacity Factor		314,121
Adjusted Coal Total		204,691,540
Reagent and By-Product Costs		34,165,968
Gas CT and CC Total		548,461,501
Total Hydro		-
Utility Owned Solar Generation		-
Total Generation Costs		959,542,167
Purchases for REPS Compliance Energy	$ 114,179,542	
Purchases for REPS Compliance Capacity	23,408,207	
Purchases from Qualifying Facilities Energy	212,217,851	
Purchases from Qualifying Facilities Capacity	43,472,451	
Purchases from Dispatchable Units Energy	46,946,023	
Emergency & DSM Purchases	2,507,667	
Allocated Economic Purchases	7,683,487	
Joint Dispatch Fuel Transfer Purchases	22,807,894	
Joint Dispatch Savings	(16,262,245)	$ 456,960,876
Total Net Generation and Purchases		1,416,503,043
Sales Totals (intersystem sales)	$ (3,013,837)	
Fuel Transfer Sales (JDA & economic sales)	(115,097,808)	(118,111,645)
Total System Fuel and Related Expenses		**$ 1,298,391,398**

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, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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	2021	$ 254,581	$ 1,026,179	$ (15,810)	$ 373,552	$ 271,177	$ 1,909,679	$ (247,666)	$ 960,017	$ 2,622,030
January	2022	379,402	1,881,753	(58,265)	533,481	400,575	3,136,946	(381,704)	950,281	3,705,523
February	2022	343,603	1,767,731	(42,922)	481,013	357,416	2,906,840	8,060,890	952,755	11,920,485
March	2022	76,749	404,018	(13,933)	131,961	81,990	680,785	(98,278)	1,114,052	1,696,559
April	2022	44,058	248,556	(15,388)	83,384	44,047	404,657	(38,076)	946,577	1,313,158
May	2022	20,309	118,528	(4,047)	37,614	22,822	195,226	(26,519)	1,008,680	1,177,387
June	2022	114,013	623,472	(10,458)	202,586	127,004	1,056,618	(155,650)	1,034,506	1,935,474
July	2022	208,987	1,131,522	(1,858)	365,845	223,328	1,927,825	(265,038)	952,195	2,614,983
August	2022	198,000	1,088,031	(5,286)	347,953	214,113	1,842,809	(259,385)	1,091,325	2,674,750
September	2022	116,916	657,674	(9,406)	210,226	125,373	1,100,783	(144,498)	988,640	1,944,924
October	2022	6,475	40,725	(5,419)	9,656	9,640	61,077	(18,917)	991,359	1,033,519
November	2022	66,315	377,299	(570)	124,434	62,224	629,702	(47,316)	944,791	1,527,177
12ME Nov	2022	$ 1,829,409	$ 9,365,489	$ (183,362)	$ 2,901,704	$ 1,939,707	$ 15,852,947	$ 6,377,843	$ 11,935,178	$ 34,165,968

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Fuel Impacts
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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	2021	$ 269,661	$ 392,854	$ (453,329)	$ (206,683)	$ (12,649,542)	$ 12,649,542	$ (1,314,581)	$ 1,314,581
January	2022	1,545,224	2,233,393	(1,432,439)	(2,755,631)	(2,368,039)	2,368,039	(149,690)	149,690
February	2022	705,011	1,040,077	(953,265)	(1,142,558)	(3,985,131)	3,985,131	(503,572)	503,572
March	2022	202,145	295,934	(224,331)	(208,642)	(11,522,259)	11,522,259	(2,078,259)	2,078,259
April	2022	838,340	1,198,576	(286,303)	(14,663)	(9,820,276)	9,820,276	(2,154,087)	2,154,087
May	2022	191,866	276,709	(256,731)	(104,733)	(5,036,503)	5,036,503	(696,258)	696,258
June	2022	545,534	767,348	(169,102)	(149,691)	(5,591,551)	5,591,551	(563,794)	563,794
July	2022	878,983	1,213,245	(287,820)	(334,830)	(9,067,708)	9,067,708	(4,890,887)	4,890,887
August	2022	844,462	1,182,822	(272,382)	(244,707)	(7,688,844)	7,688,844	(1,358,642)	1,358,642
September	2022	637,593	905,491	(216,463)	(179,009)	(8,806,019)	8,806,019	(1,180,178)	1,180,178
October	2022	328,807	470,829	(83,413)	(192,390)	390,969	(390,969)	663,579	(663,579)
November	2022	695,861	1,045,293	(46,753)	(65,965)	(11,462,678)	11,462,678	(2,035,876)	2,035,876
Total		$ 7,683,487		$ (4,682,333)		$ (87,607,581)		$ (16,262,245)	

Note: Totals may not sum due to rounding

		Fuel Transfer Payments	
		Purchases	**Sales**
December	2021	$ 1,523,898	$ 14,173,440
January	2022	3,140,024	5,508,063
February	2022	2,748,088	6,733,219
March	2022	768,887	12,291,146
April	2022	801,042	10,621,319
May	2022	2,524,377	7,560,880
June	2022	1,971,281	7,562,832
July	2022	1,230,735	10,298,444
August	2022	1,444,562	9,133,405
September	2022	1,204,288	10,010,307
October	2022	5,172,089	4,781,120
November	2022	278,622	11,741,299
		$ 22,807,894	$ 110,415,475
			$ (87,607,581)

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Payments
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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	2021	593,459	66,598	148	(148)	593,607	66,598	$ 23.88	$ 22.88	$ 1,523,898	$ 14,173,440	$ -	$ 12,649,542
January	2022	219,077	110,789	(14,049)	14,049	219,077	124,838	$ 25.14	$ 25.15	3,140,024	5,508,063	-	2,368,039
February	2022	274,009	93,961	(14,865)	14,865	274,009	108,826	$ 24.57	$ 25.25	2,748,088	6,733,219	-	3,985,131
March	2022	601,512	33,030	(1,652)	1,652	601,512	34,682	$ 20.43	$ 22.17	768,887	12,291,146	-	11,522,259
April	2022	547,580	37,513	(3,515)	3,515	547,580	41,028	$ 19.40	$ 19.52	801,042	10,621,319	-	9,820,276
May	2022	405,528	129,683	(6,365)	6,365	405,528	136,048	$ 18.64	$ 18.56	2,524,377	7,560,880	-	5,036,503
June	2022	374,099	96,478	(4,439)	4,439	374,099	100,917	$ 20.22	$ 19.53	1,971,281	7,562,832	-	5,591,551
July	2022	467,244	58,466	13,072	(13,072)	480,316	58,466	$ 21.44	$ 21.05	1,230,735	10,298,444	-	9,067,708
August	2022	409,567	69,568	19,179	(19,179)	428,746	69,568	$ 21.30	$ 20.76	1,444,562	9,133,405	-	7,688,844
September	2022	490,046	61,161	(709)	709	490,046	61,869	$ 20.43	$ 19.47	1,204,288	10,010,307	-	8,806,019
October	2022	257,001	263,616	(9,189)	9,189	257,001	272,805	$ 18.60	$ 18.96	5,172,089	4,781,120	390,969	-
November	2022	630,563	11,901	4,806	(4,806)	635,368	11,901	$ 18.48	$ 23.41	278,622	11,741,299	-	11,462,678
Total		5,269,682	1,032,763	(17,578)	17,578	5,306,887	1,087,546			$ 22,807,894	$ 110,415,475	$ 390,969	$ 87,998,550

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, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Harrington Workpaper 8

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC Retail			
Residential	16,610,751		16,610,751
Small General Service	1,792,730		1,792,730
Medium General Service	10,332,062		10,332,062
Large General Service	9,225,261		9,225,261
Lighting	380,260		380,260
NC Retail	38,341,063		38,341,063
SC Retail	6,769,010	33,310	6,802,320
Total Wholesale	16,853,473		16,853,473
Total Adjusted NC System Sales	61,963,546	33,310	61,996,856
NC as a percentage of total	61.88%	0.00%	61.84%
SC as a percentage of total	10.92%	100.00%	10.97%
Wholesale as a percentage of total	27.20%	0.00%	27.18%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		33,310	
Marginal Fuel rate per MWh for SC NEM	$	22.54	
Fuel Benefit to be directly assigned to SC	$	750,664	
System Fuel Expense	$	1,298,391,398	Exh 2 Sch 1 Pg 1
Fuel benefit to be directly assigned to SC Retail		750,664	
Total Adjusted System Fuel Expense	$	1,299,142,062	Exh 2 Sch 1 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Normalized Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

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	16,297,009	295,534	134,304		16,726,846
Small General Service	1,803,155	383,515	17,453		2,204,123
Medium General Service	10,156,058	59,185	(6,486)		10,208,757
Large General Service	8,284,574	(5,387)	3,047		8,282,234
Lighting	341,023	0	871		341,894
NC Retail	36,881,818	732,846	149,190		37,763,854
SC Retail	6,005,213	108,276	1,294	33,310	6,148,093
Total Wholesale	17,020,253	398,788	125,791		17,544,832
Total Adjusted NC System Sales	59,907,284	1,239,910	276,275	33,310	61,456,779
NC as a percentage of total	61.56%				61.45%
SC as a percentage of total	10.02%				10.00%
Wholesale as a percentage of total	28.41%				28.55%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		33,310	
Marginal Fuel rate per MWh for SC NEM	$	22.54	
Fuel Benefit to be directly assigned to SC	$	750,664	
System Fuel Expense	$	1,283,118,386	Exh 2 Sch 2 Pg 1
Fuel benefit to be directly assigned to SC Retail		750,664	
Total Adjusted System Fuel Expense	$	1,283,869,051	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, 2021
Docket No. E-2, Sub 1272

Harrington Workpaper 9a

Line No.	Description	Formula	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Residential		333,221	88.69	295,534	11.31	37,687
	Commercial						
2	Small and Medium General Service		436,905	87.78	383,515	12.22	53,390
	Industrial						
3	Large General Service		76,565	77.30	59,185	22.70	17,380
	OPA						
4	Other Public Authority (Large General Service)		(5,568)	96.74	(5,387)	3.26	(182)
5	Total Retail	L1+ L2+ L3 + L4	841,122		732,846		108,276
6	Wholesale		398,788				
7	Total Company	L5 + L6	1,239,910		732,846		108,276

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Adjustment - MWh
Twelve Months Ended March 31, 2021
Docket No. E-2, Sub 1272

Harrington Workpaper 9b

		Residential MWH Adjustment	Commercial MWH Adjustment	Industrial MWH Adjustment	OPA MWH Adjustment	Total Retail MWH Adjustment	Wholesale MWH Adjustment
April	**2020**	45,765	110,420	16,934	-	173,119	103,550
May	**2020**	47,062	182,876	23,276	-	253,214	151,622
June	**2020**	42,760	167,040	5,855	1,497	217,151	48,358
July	**2020**	28,472	9,736	5,159	1,048	44,415	30,845
August	**2020**	(51,620)	(20,708)	(10,392)	(2,749)	(85,470)	(43,031)
September	**2020**	(60,969)	(29,766)	(10,769)	(4,015)	(105,519)	(33,536)
October	**2020**	24,647	14,187	12,957	2,808	54,599	1,238
November	**2020**	80,347	-	(137,348)	(4,608)	(61,609)	59,592
December	**2020**	75,383	-	168,141	-	243,524	38,732
January	**2021**	11,714	1,362	780	52	13,908	8,488
February	**2021**	44,750	1,758	1,973	398	48,880	16,310
March	**2021**	44,909	-	-	-	44,909	16,619
12ME March	**2021**	**333,221**	**436,905**	**76,565**	**(5,568)**	**841,122**	**398,788**

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment - MWh
Twelve Months Ended March 31, 2021
Docket No. E-2, Sub 1272

Harrington Workpaper 9c

Rate Schedule	Estimation Method[1]	Reference	NC Proposed MWH Adjustment [1]	SC Proposed MWH Adjustment [1]	Wholesale Proposed MWH Adjustment
Residential	Regression	RES	134,304	1,562	
General:					
General Service Small	Regression	SGS	17,453	1,069	
General Service Medium	Customer	MGS	(6,486)	(1,347)	
Total General			10,967	(278)	
Lighting:					
Street Lighting	Regression	SLS/SLR	769	23	
Sports Field Lighting	Regression	SFLS	66	(1)	
Traffic Signal Service	Regression	TSS/TFS	37	(12)	
Total Street Lighting			871	11	
Industrial:					
I - Textile	Customer	LGS	-	-	
I - Nontextile		LGS	3,047	-	
Total Industrial			3,047	-	
Total			**149,190**	**1,294**	**125,791**

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. See ND330 for further explanation.

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales - NERC 5 year Average
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Harrington Workpaper 10

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC Retail			
Residential	16,610,751		16,610,751
Small General Service	1,792,730		1,792,730
Medium General Service	10,332,062		10,332,062
Large General Service	9,225,261		9,225,261
Lighting	380,260		380,260
NC Retail	38,341,063		38,341,063
SC Retail	6,769,010	33,310	6,802,320
Total Wholesale	16,853,473		16,853,473
Total Adjusted NC System Sales	61,963,546	33,310	61,996,856
NC as a percentage of total	61.88%	0.00%	61.84%
SC as a percentage of total	10.92%	100.00%	10.97%
Wholesale as a percentage of total	27.20%	0.00%	27.18%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		33,310	
Marginal Fuel rate per MWh for SC NEM	$	22.54	
Fuel Benefit to be directly assigned to SC	$	750,664	
System Fuel Expense	$	1,329,242,819	Exh 2 Sch 3 Pg 1
Fuel benefit to be directly assigned to SC Retail		750,664	
Total Adjusted System Fuel Expense	$	1,329,993,484	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, 2020
Docket No. E-2, Sub 1272

Harrington Workpaper 11

Generator Step Up Loss % **0.2074%**

	kWh @ Meter	E-2 Allocation	kWh @ Prod Out.	E-1 Allocation	Losses
NC RES	15,116,836,578	25.8420%	15,701,057,542	26.0737%	584,220,964
NC RES-TOU	410,328,321	0.7014%	426,186,295	0.7077%	15,857,974
NC SGS	1,718,899,004	2.9384%	1,785,312,008	2.9648%	66,413,004
NC SGS-CLR	48,786,279	0.0834%	50,671,271	0.0841%	1,884,992
NC MGS-TOU	7,752,733,902	13.2532%	8,039,202,208	13.3502%	286,468,306
NC MGS	2,415,688,184	4.1296%	2,506,947,379	4.1631%	91,259,195
NC SI	30,625,111	0.0524%	31,672,133	0.0526%	1,047,022
NC LGS	990,915,145	1.6940%	1,021,169,521	1.6958%	30,254,376
NC LGS-TOU	1,752,903,144	2.9966%	1,806,161,547	2.9994%	53,258,403
NC LGS-RTP	5,583,478,093	9.5449%	5,723,794,255	9.5051%	140,316,162
NC TSS	4,661,461	0.0080%	4,841,613	0.0080%	180,152
NC ALS	255,632,931	0.4370%	265,512,387	0.4409%	9,879,456
NC SLS	85,980,452	0.1470%	89,303,342	0.1483%	3,322,890
NC SFLS	943,392	0.0016%	972,181	0.0016%	28,789
Total NCR	36,168,411,997	61.8293%	37,452,803,680	62.1954%	1,284,391,683
NCWHS incl . NCEMPA	16,398,692,582	28.0333%	16,637,536,858	27.6289%	238,844,275
Total NC	52,567,104,579	89.8627%	54,090,340,538	89.8243%	1,523,235,958
SC RES	1,943,026,554	3.3216%	2,018,118,776	3.3514%	75,092,222
SC RET	33,291,698	0.0569%	34,578,324	0.0574%	1,286,626
SC SGS	236,111,440	0.4036%	245,224,167	0.4072%	9,112,727
SC SGS-CLR	5,745,041	0.0098%	5,967,070	0.0099%	222,029
SC MGS-TOU	1,054,298,004	1.8023%	1,093,107,498	1.8153%	38,809,494
SC MGS	459,629,167	0.7857%	476,692,225	0.7916%	17,063,058
SC SI	12,056,951	0.0206%	12,467,929	0.0207%	410,978
SC LGS	565,652,880	0.9670%	582,837,257	0.9679%	17,184,377
SC LGS-TOU	213,493,431	0.3650%	219,357,906	0.3643%	5,864,475
SC LGS-CRTL-TOU	666,103,200	1.1387%	679,947,604	1.1291%	13,844,404
SC LGS-RTP	663,130,532	1.1336%	678,777,952	1.1272%	15,647,420
SC TSS	1,966,910	0.0034%	2,042,925	0.0034%	76,015
SC ALS	59,418,391	0.1016%	61,714,736	0.1025%	2,296,345
SC SLS	16,026,332	0.0274%	16,645,702	0.0276%	619,370
SC SFLS	110,108	0.0002%	113,476	0.0002%	3,368
Total SCR	5,930,060,639	10.1373%	6,127,593,547	10.1757%	197,532,908
SCWHS		0.0000%		0.0000%	0
Total SC	5,930,060,639	10.1373%	6,127,593,547	10.1757%	197,532,908
Total System	58,497,165,218	100.0000%	60,217,934,085	100.0000%	1,720,768,866

	Cost of Service Data Summarized			
	kWh @ Meter	**kWh @ Generator**	**Losses (kWh)**	**Loss Percent**
Residential	15,527,164,899	16,160,767,721	633,602,822	4.0810%
SGS	1,772,346,744	1,844,651,435	72,304,691	4.0800%
MGS	10,199,047,197	10,599,809,956	400,762,759	3.9290%
LGS	8,327,296,382	8,568,900,643	241,604,261	2.9010%
Lighting	342,556,775	356,527,490	13,970,715	4.0780%
Total NC Retail	36,168,411,997	37,530,657,245	1,362,245,248	3.7660%
Total NC Retail	36,168,411,997	37,530,657,245	1,362,245,248	3.7660%
SC Retail	5,930,060,639	6,140,331,045	210,270,406	3.5460%
12ME NEM Generation	**30,159,869**	31,229,338	1,069,469	3.5460%
Total SC Retail	5,960,220,508	6,171,560,383	211,339,875	3.5460%
All other jurisdictions	16,368,532,713	16,640,892,155	272,359,441	1.6640%
Total System	58,497,165,218	60,343,109,782	1,845,944,564	3.1560%
SC Retail + All Other	22,328,753,221	22,812,452,537	483,699,316	2.1660%

Line Loss Calculations for Projected Fuel Costs	**MWh @ Meter**	**MWh @ Generator**	**Losses (MWh)**	**Loss Percent**
Total NC Retail	38,341,063	39,841,494	1,500,431	3.9130%
Total SC Retail	6,802,320	7,052,398	250,078	3.6760%
All other jurisdictions	16,853,473	17,138,660	285,187	1.6920%
Total System	61,996,856	64,032,552	2,035,696	3.2840%
Allocation percent - NC retail	61.84%	62.22%		

Line Loss Calculations for Normalized Test Period Sales	**MWh @ Meter**	**MWh @ Generator**	**Losses (MWh)**	**Loss Percent**
Total NC Retail	37,763,854	39,241,696	1,477,842	3.9130%
Total SC Retail	6,148,093	6,374,119	226,026	3.6760%
All other jurisdictions	17,544,832	17,841,718	296,886	1.6920%
Total System	61,456,779	63,457,534	2,000,755	3.2560%
Allocation percent - NC retail	61.45%	61.84%		

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, 2021
Docket No. E-2, Sub 1272

Harrington Workpaper 12

									Remove Partial Year Impacts						Add Impact of Approved Rate Changes During Test Year					
Revenue Class (1)	Annual Sales (2) per RMC2B - Adjusted to tie to RMCRY2	Annual EE Opt-Out Sales (3) per RMCRY14E	Annual DSM Opt-Out Sales (4) per RMCRY14E	Annual Customer Count (5) per RMC2B	Annual Rider JAA kWh Units (6) per RMC2B	Annual Rider JAA Demand Units (7) per PMCM7M	Annual Customer Count (Adjusted for Premise Billing) (8) = (5) adjusted by RMCRY10	Annual Revenues (9) per RMC2B	Test Year Rate Changes** (10) - See Annualization Adjustment Worksheet	Opt-Out Credit Due to Jan 2021 EE Rate (11) per RMCRY14	Opt-Out Credit Due to Jan. 2021 DSM Rate (12) per RMCRY15	NC Rate Case (13) per Report PMCM7M Worksheet	REPS Revenue Due to December 2020 Rate Change (14) per RMCRY10	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	16,363,387,435	0	0	15,294,135	16,363,387,435	0	14,812,068	$1,843,131,959	($1,970,211)	$0	$0	$0	($661,393)	$1,845,763,564	($42,559,090)	$0	$0	$0	($2,369,931)	$1,800,834,543
Residential	16,296,998,427	0	0	15,177,941	16,296,998,427	0	14,730,183	$1,820,731,667	($1,948,432)	$0	$0	$0	($657,925)	$1,823,338,025	($42,050,330)	$0	$0	$0	($2,356,829)	$1,778,930,866
SGS	1,692	0	0	2	1,692	0	0	$192	($2)	$0	$0	$0	$0	$194	($8)	$0	$0	$0	$0	$185
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	66,387,316	0	0	116,192	66,387,316	0	81,885	$22,400,100	($21,777)	$0	$0	$0	($3,468)	$22,425,346	($508,752)	$0	$0	$0	($13,102)	$21,903,492
Commercial	11,286,623,086	3,907,286,711	3,946,983,626	2,524,258	1,992,626,856	28,686,945	2,363,415	$1,021,364,698	($13,144,860)	($250,302)	$36,433	$0	($843,182)	$1,035,138,872	($43,815,513)	($1,641,851)	$236,113	$87	($3,001,537)	$989,727,648
Residential	10,306	0	0	32	10,306	0	0	$1,509	($0)	$0	$0	$0	($18)	$1,527	($29)	$0	$0	$87	$0	$1,585
SGS	1,782,249,117	16,328,355	16,600,807	2,061,313	1,732,994,183	0	1,817,836	$217,193,982	($336,695)	($1,352)	$198	$0	($648,711)	$218,178,234	($7,456,096)	($6,858)	$996	$0	($2,308,652)	$208,419,349
MGS	8,250,885,512	2,805,529,427	2,879,069,560	446,582	57,005,997	26,439,834	389,477	$675,768,959	($11,374,657)	($186,269)	$27,440	$0	($139,796)	$687,124,583	($31,693,640)	($1,178,322)	$172,744	$0	($494,635)	$655,941,886
LGS	1,050,861,781	1,074,130,081	1,039,539,988	1,139	0	2,247,110	877	$77,605,965	($1,366,722)	($63,361)	$8,795	$0	($315)	$78,918,435	($3,117,461)	($451,135)	$62,372	$0	($1,114)	$76,188,622
Lighting	202,616,370	11,298,848	11,773,271	15,192	202,616,370	0	155,225	$50,794,284	($66,787)	$680	$0	$0	($54,343)	$50,916,093	($1,548,287)	($5,536)	$0	$0	($197,136)	$49,176,207
Industrial	7,790,186,720	8,398,189,643	8,392,622,238	41,135	2,273,651,120	18,386,676	20,924	$499,159,713	($10,465,043)	($552,935)	$78,949	$0	($69,567)	$509,220,337	($26,886,128)	($3,527,706)	$503,144	$0	($244,811)	$485,113,960
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	16,586,855	8,101,261	8,248,425	11,893	-141,192	0	3,186	$1,828,247	($3,694)	($679)	$99	$0	($10,696)	$1,842,056	($70,435)	($3,403)	$495	$0	($37,280)	$1,737,248
MGS	1,905,172,708	1,569,000,798	1,568,283,987	26,707	1,543,251,934	5,590,967	7,194	$145,075,837	($2,801,756)	($108,872)	$15,514	$0	($24,443)	$147,808,678	($9,431,213)	($658,980)	$94,097	$0	($84,167)	$138,858,181
LGS	5,855,374,119	6,814,425,099	6,809,205,786	2,357	730,460,025	12,795,709	8,888	$349,470,175	($7,655,067)	($443,779)	$63,336	$0	($29,708)	$356,774,507	($17,285,304)	($2,862,059)	$408,552	$0	($103,984)	$341,838,725
Lighting	13,053,038	6,662,485	6,884,040	178	80,353	0	1,656	$2,785,454	($4,526)	$395	$0	$0	($4,720)	$2,795,096	($99,175)	($3,265)	$0	$0	($19,379)	$2,679,806
Public Streets & Highways	63,281,045	0	0	10,967	63,281,045	0	9,716	$17,232,066	($24,907)	$0	$0	$0	($3,376)	$17,260,349	($480,473)	$0	$0	$0	($12,339)	$16,767,537
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	4,316,965	0	0	5,388	4,316,965	0	5,083	$415,826	($389)	$0	$0	$0	($1,710)	$417,925	($17,045)	$0	$0	$0	($6,455)	$394,425
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	58,964,080	0	0	5,579	58,964,080	0	4,633	$16,816,240	($24,518)	$0	$0	$0	($1,667)	$16,842,424	($463,428)	$0	$0	$0	($5,884)	$16,373,112
Military	1,378,339,726	1,587,737,510	1,587,737,510	48	1,920	3,269,218	38	$79,404,048	($1,759,206)	($90,128)	$12,875	$0	($134)	$81,086,136	($3,728,568)	($666,850)	$95,264	$0	($445)	$77,928,709
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	1,378,337,806	1,587,737,510	1,587,737,510	48	0	3,269,218	38	$79,403,832	($1,759,206)	($90,128)	$12,875	$0	($134)	$81,085,920	($3,728,555)	($666,850)	$95,264	$0	($445)	$77,928,505
Lighting	1,920	0	0	0	1,920	0	0	$216	$0	$0	$0	$0	$0	$216	($13)	$0	$0	$0	$0	$203
NC Retail	36,881,818,012	13,893,213,864	13,927,343,374	17,870,543	20,692,948,376	50,342,839	17,206,161	$3,460,292,485	($27,364,228)	($893,364)	$128,257	$0	($1,577,652)	$3,488,469,258	($117,469,772)	($5,836,407)	$834,521	$87	($5,629,063)	$3,370,372,397
	0	0	0	0	0	0		0	$0	0	0	0	-20,000		0			0		
Rate Schedules (excludes REPS)																				
RES (includes RES-RECD)	15,872,746,543	0	0	14,920,005	15,872,746,543	0		$1,779,670,819	($1,491,866)	$0	$0	$93,434,533	-$657,943	$1,688,386,095	($32,748,509)	$0	$0	$0		$1,655,637,586
SGS	1,743,237,348	24,378,406	24,792,006	1,965,791	1,743,237,348	0		$212,566,970	($331,864)	($2,027)	$296	$25,847,772	-$622,980	$187,672,310	($7,316,203)	($10,239)	$1,488	$0		$180,364,858
MGS	2,410,887,243	299,114,818	301,087,022	202,355	0	12,275,816		$245,774,966	$1,398,660	($20,943)	$3,027	$26,773,309	-$84,885	$217,669,967	($3,676,210)	($125,628)	$18,065	$0		$214,101,320
SGS-TOU	7,688,582,175	4,071,497,132	4,142,246,640	260,468	0	19,702,908		$568,874,848	($15,572,806)	($273,936)	$39,889	$15,122,131	-$100,816	$569,192,292	($37,357,348)	($1,710,029)	$248,535	$0		$533,296,437
LGS	958,213,380	1,070,364,265	1,078,297,927	1,027	0	2,363,879		$76,449,715	($1,091,635)	($67,678)	$9,724	$18,080,487	-$2,119	$59,405,028	($2,573,385)	($449,553)	$64,698	$0		$57,216,497
LGS-TOU	1,772,188,848	1,877,485,927	1,829,742,859	1,551	0	3,404,606		$125,285,957	($2,193,546)	($126,927)	$17,759	$3,741,436	-$1,829	$123,630,728	($5,491,891)	($788,544)	$109,785	$0		$118,817,596
LGS-RTP	2,105,192	2,105,192	2,105,192	13	0	45,573		$1,189,315	($88,784)	$0	$0	$36,109	$0	$1,241,990	($200,405)	($884)	$126	$0		$1,042,343
LGS-RTP-TOU	5,552,066,286	6,524,373,391	6,524,373,391	953	0	12,497,980		$303,554,984	($7,407,031)	($402,663)	$57,523	$11,194,564	-$2,177	$299,424,490	($15,865,640)	($2,740,237)	$391,462	$0		$285,907,624
LGS Class	8,284,573,706	9,474,328,775	9,434,519,369	3,544	0	18,312,038		$506,479,971	($10,780,995)	($597,267)	$85,006	$33,052,596	($6,125)	$483,702,235	($24,131,321)	($3,979,218)	$566,071	$0		$462,984,061
Rate Class																				
Residential	16,297,008,733	0	0	15,177,973	16,297,008,733	0	14,730,183	$1,820,733,176	($1,948,433)	$0	$0	$0	($657,943)	$1,823,339,552	($42,050,359)	$0	$0	$87	($2,356,829)	$1,778,932,451
SGS	1,803,154,629	24,429,616	24,849,232	2,078,596	1,737,171,648	0	1,826,105	$219,438,247	($340,780)	($2,032)	$297	$0	($661,117)	$220,438,409	($7,543,585)	($10,260)	$1,491	$0	($2,352,387)	$210,551,207
MGS	10,156,058,220	4,374,530,225	4,447,353,547	473,289	1,600,257,931	32,030,801	396,670	$820,844,796	($14,176,412)	($295,141)	$42,955	$0	($164,239)	$834,933,261	($41,124,853)	($1,837,303)	$266,841	$0	($578,802)	$794,800,067
LGS	8,284,573,706	9,476,292,690	9,436,483,284	3,544	730,460,025	18,312,038	9,803	$506,479,971	($10,780,995)	($597,267)	$85,006	$0	($30,156)	$516,778,862	($24,131,321)	($3,980,043)	$566,189	$0	($105,543)	$495,955,852
Lighting	341,022,724	17,961,333	18,657,311	137,141	328,050,039	0	243,400	$92,796,294	($117,608)	$1,076	$0	$0	($64,197)	$92,979,175	($2,619,654)	($8,801)	$0	$0	($235,501)	$90,132,820
	36,881,818,012	13,893,213,864	13,927,343,374	17,870,543	20,692,948,376	50,342,839	17,206,161	$3,460,292,485	($27,364,228)	($893,364)	$128,257	$0	($1,577,652)	$3,488,469,258	($117,469,772)	($5,836,407)	$834,521	$87	($5,629,063)	$3,370,372,397

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 13**
North Carolina Annual Fuel and Fuel Related Expense
Actual MWH Sales by Jurisdiction - Subject to Weather
Twelve Months Ended March 31, 2021
Docket No. E-2, Sub 1272

Line No.	Description	Reference	North Carolina	South Carolina	Retail Total Company	% NC	% SC
1	Residential	Company Records	16,363,387	2,086,332	18,449,719	88.69	11.31
2	Commercial	Company Records	11,286,623	1,571,072	12,857,695	87.78	12.22
3	Industrial	Company Records	7,790,187	2,287,239	10,077,425	77.30	22.70
4	Other Public Authority	Company Records	1,378,340	46,435	1,424,775	96.74	3.26
5	Total Retail Sales subject to weather	Sum 1 through 4	36,818,537	5,991,078	42,809,615		
6	Lighting	Company Records	63,281	14,135	77,416		
7	Total Retail Sales	Line 5 + Line 6	36,881,818	6,005,213	42,887,031		

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2020 Production Plant Allocation Factors
Docket No. E-2, Sub 1272

Harrington Workpaper 14

2020 Total Production Plant	System	NC Retail	Residential	Small GS	Med GS	Lrg GS	Ltg
All - Production Plant	17,741,420	10,798,235	5,371,140	633,930	3,117,631	1,675,534	-
NC Retail % to Total System		60.86%	30.27%	3.57%	17.57%	9.44%	0.00%
Allocation of Classes to Total NC Retail		100.00%	49.74%	5.87%	28.87%	15.52%	0.00%

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Scenario Differences
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Harrington Workpaper 15

Exhibit 2 Schedule 1: Line Loss

Line Losses	Exh 2 Sch 1 Pg 1 Ln 16	(2,310,113)
Generation	Exh 2 Sch 1 Pg 1 Ln 10	59,686,315
	%	-3.870%
	Multiplier	1.038704

Schedule 2: Proposed Nuclear Capacity Factor & Normalized Sales

Normalized Sales	Exh 4, Total Co., Ln 4	61,423,469
Sales Forecast	Exh 2 Sch 1 Pg 1 Ln 18	61,963,546
Difference		(540,077)
Gross up for losses	Difference x Multiplier	(560,980)
	MWh changes in Coal	(560,980)
	MWH changes in Losses	20,903

	Before Adj	Adj	Total
Total Coal MWh	7,518,351	(560,980)	6,957,371
Total Losses MWh	(2,310,113)	20,903	(2,289,210)
	5,208,238	(540,077)	4,668,161

	Before Adj	After Adj	Adjustment
Total Coal $	$ 204,691,540	$ 189,418,528	$ (15,273,012)

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

		Nuclear-MWHs	Nuclear Costs
Nuclear	WP 1	29,337,015	$ 172,223,158
Nuclear - NERC Average	WP 2	27,892,328	$ 163,742,110
	Adjustment	(1,444,687)	$ (8,481,048)

		Coal-MWH	Coal Costs	
Coal MWh	WP 3, WP4	7,518,351	$ 204,691,540	
Adjustment from Above	Adjustment above	1,444,687	$ 39,332,470	(Priced at the avg Coal $/MWH)
		8,963,038	$ 244,024,009	

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Projected Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Harrington Workpaper 16

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 277,781,551	$ 4,000,667	$ 281,782,217
2	Amount in 2020 Filing: Docket E-2 Sub 1250	269,804,228	(9,714,001)	260,090,227
3	Reduction in prior year docket in excess of 2.5%	-		-
4	Increase/(Decrease)	$ 7,977,322	$ 13,714,667	$ 21,691,990
5	2.5% of 2020 NC revenue of $3,458,306,941			86,457,674
6	Amount over 2.5%			0

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

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Dispatchable Purchased Energy	$ 43,444,341	61.59%	$ 26,757,369
Prior Year	Purchases for REPS Compliance Energy	131,543,318	61.59%	81,017,530
Prior Year	Purchases for REPS Compliance Capacity	26,962,441	60.07%	16,195,509
Prior Year	Purchases from Qualifying Facilities Energy	191,949,817	61.59%	118,221,892
Prior Year	Purchases from Qualifying Facilities Capacity	39,344,300	60.07%	23,632,911
Prior Year	Allocated Economic Purchases	6,460,492	61.59%	3,979,017
Prior Year	Total	$ 439,704,709		$ 269,804,228

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Normalized Sales
Billing Period December 1, 2021 - November 30, 2022
Docket No. E-2, Sub 1272

Harrington Workpaper 17

Line No.	Description		Forecast $		EMF (Over)/Under Collection $		Total $
1	Amount in current docket	$	274,839,356	$	4,000,667	$	278,840,023
2	Amount in 2020 Filing: Docket E-2 Sub 1250		266,267,477		(9,714,001)		256,553,477
3	Reduction in prior year docket in excess of 2.5%		-				-
4	Increase/(Decrease)	$	8,571,879	$	13,714,667	$	22,286,546
5	2.5% of 2020 NC revenue of $3,458,306,941						86,457,674
6	Amount over 2.5%						0

			System Cost	Alloc %		NC Alloc. Forecast
WP 4	Purchases from Dispatchable Units	$	46,946,023	61.45%	$	28,847,310
WP 4	Purchases for REPS Compliance		114,179,542	61.45%		70,160,845
WP 4	Purchases for REPS Compliance Capacity		23,408,207	60.86%		14,247,300
WP 4	Purchases from Qualifying Facilities Energy		212,217,851	61.45%		130,403,254
WP 4	Purchases from Qualifying Facilities Capacity		43,472,451	60.86%		26,459,312
WP 4	Allocated Economic Purchases		7,683,487	61.45%		4,721,336
	Total	$	447,907,561		$	274,839,356

			System Cost	Alloc %		NC Alloc. Forecast
Prior Year	Dispatchable Purchased Energy	$	43,444,341	60.64%	$	26,345,873
Prior Year	Purchases for REPS Compliance Energy		131,543,318	60.64%		79,771,578
Prior Year	Purchases for REPS Compliance Capacity		26,962,441	60.07%		16,195,509
Prior Year	Purchases from Qualifying Facilities Energy		191,949,817	60.64%		116,403,782
Prior Year	Purchases from Qualifying Facilities Capacity		39,344,300	60.07%		23,632,911
Prior Year	Allocated Economic Purchases		6,460,492	60.64%		3,917,825
Prior Year	Total	$	439,704,709		$	266,267,477

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test-Detail Calculation
Test Period April 2020 - March 2021
Docket No. E-2, Sub 1272

Harrington Workpaper 18

Line No.		Reference	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	* Dec-20	** Jan-21	Feb-21	Mar-21	12ME
1	System kWh Sales, at generation		4,110,876,368	4,104,424,018	5,000,502,514	6,194,287,766	6,438,542,023	5,508,599,869	4,480,744,528	4,571,453,139	5,115,507,585	5,742,700,838	5,577,624,231	4,952,199,091	61,797,461,971
2	NC Retail kWh Sales, at generation		2,633,443,825	2,517,777,010	3,015,363,245	3,638,004,368	3,927,823,747	3,550,264,938	2,824,523,664	2,905,109,796	3,000,101,938	3,481,525,093	3,499,840,925	3,171,280,410	38,165,058,959
3	NC Retail % of Sales	Line 2 / Line 1	64.06%	61.34%	60.30%	58.73%	61.00%	64.45%	63.04%	63.55%	58.65%	60.63%	62.75%	64.04%	61.76%
	Total Purchase Power, Excl. JDA														
4	System Purchase Power, Excl. JDA		$ 30,512,264	$ 38,078,563	$ 32,831,693	$ 42,216,785	$ 38,292,614	$ 31,120,830	$ 22,997,645	$ 29,996,390	$ 26,855,321	$ 22,748,840	$ 23,672,728	$ 21,276,393	$ 360,600,065
5	NC Purchase Power	Line 4 * Line 3	$ 19,546,278	$ 23,358,534	$ 19,797,906	$ 24,794,594	$ 23,360,357	$ 20,057,219	$ 14,497,009	$ 19,062,386	$ 15,749,894	$ 13,791,535	$ 14,854,135	$ 13,624,938	$ 222,700,453
6	NC Retail kWh Sales		2,545,360,664	2,433,609,079	2,914,204,597	3,515,386,378	3,795,408,033	3,430,875,386	2,730,391,072	2,807,754,547	2,899,315,724	3,363,691,275	3,381,318,468	3,064,502,789	36,881,818,012
7	NC Incurred Rate	Line 5 / Line 6 * 100	0.768	0.960	0.679	0.705	0.615	0.585	0.531	0.679	0.543	0.410	0.439	0.445	0.604
	Total Capacity														
8	System Capacity		$ 5,383,105	$ 7,679,028	$ 5,836,636	$ 16,705,855	$ 11,813,564	$ 9,036,989	$ 6,175,861	$ 2,930,016	$ 4,775,494	$ 4,176,478	$ 3,146,493	$ 4,083,924	$ 81,743,444
9	NC Capacity (Avg Monthly NC % of System Sales for the Period)	61.565%	$ 3,314,100	$ 4,727,580	$ 3,593,315	$ 10,284,931	$ 7,273,001	$ 5,563,607	$ 3,802,158	$ 1,803,859	$ 2,940,025	$ 2,571,241	$ 1,937,133	$ 2,514,261	$ 50,325,212
10	NC Incurred Rate	Line 9/Line 6*100	0.130	0.194	0.123	0.293	0.192	0.162	0.139	0.064	0.101	0.076	0.057	0.082	0.136
11	Total NC Incurred Rate	Line 7 + Line 10	0.898	1.154	0.803	0.998	0.807	0.747	0.670	0.743	0.645	0.486	0.497	0.527	0.740
12	Billed Rate	Billed Rates Below	0.734	0.734	0.734	0.734	0.734	0.734	0.734	0.734	0.728	0.716	0.715	0.715	
13	(Over)/Under cents per kwh	Line 131- Line 12	0.164	0.420	0.068	0.263	0.073	0.012	(0.064)	0.009	(0.084)	(0.229)	(0.219)	(0.188)	
14	(Over)/Under $	Line 6 * Line 13 /100	$ 4,165,685	$ 10,212,194	$ 1,987,512	$ 9,260,367	$ 2,757,549	$ 422,369	$ (1,754,503)	$ 244,371	$ (2,423,300)	$ (7,704,782)	$ (7,390,216)	$ (5,776,579)	$ 4,000,667

Billed Rate from Docket E-2, Sub 1204 - Apr'20-Nov'20

15	Purchases from Dispatchable Units & Economic Purchases	19,479,187	2019 Harrington WP4
16	Total MWH Sales	62,155,919	2019 Harrington WP3
17	Billed Rate for Purchases	**0.031**	
18	Renewables (energy)	168,625,939	2019 Harrington WP4
19	Total MWH Sales	62,155,919	2019 Harrington WP3
20	Billed Rate for Renewables	**0.271**	
21	QF Purchases (energy)	193,990,299	2019 Harrington WP4
22	Total MWH Sales	62,155,919	2019 Harrington WP3
23	Billed Rate for Renewables	**0.312**	
24	Capacity (REPS and QF)	74,415,842	2019 Harrington WP4
25	Total MWH Sales	62,155,919	2019 Harrington WP3
26	Billed Rate for Capacity	**0.120**	
27	Total Billed Rate	**0.734**	To Line 12

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

	Prior Bill Rate (Sub 1204)	New Bill Rate (Sub 1250)	December Blended Rate	
Approved Rates	0.734	0.715		
Ratios of Days to rate	67.65%	32.35%		
Prorated Rate	**0.497**	**0.231**	**0.728**	To Line 12

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

	Prior Bill Rate (Sub 1204)	New Bill Rate (Sub 1250)	January Blended Rate	
Approved Rates	0.734	0.715		
Ratios of Days to rate	1.868%	98.13%		
Prorated Rate	**0.014**	**0.702**	**0.716**	To Line 12

Billed Rate from Docket E-2, Sub 1250 - Feb'21-Mar'21

Purchases from Dispatchable Units & Economic Purchases	49,904,833	2020 Harrington WP4
Total MWH Sales	61,484,301	2020 Harrington WP3
Billed Rate for Purchases	**0.081**	
Renewables (energy)	131,543,318	2020 Harrington WP4
Total MWH Sales	61,484,301	2020 Harrington WP3
Billed Rate for Renewables	**0.214**	
QF Purchases (energy)	191,949,817	2020 Harrington WP4
Total MWH Sales	61,484,301	2020 Harrington WP3
Billed Rate for Renewables	**0.312**	
Capacity (REPS and QF)	66,306,741	2020 Harrington WP4
Total MWH Sales	61,484,301	2020 Harrington WP3
Billed Rate for Capacity	**0.108**	
Total Billed Rate	**0.715**	To Line 12

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

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	)	**KENNETH D. CHURCH FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS,**
Charge Adjustments for Electric Utilities	)	**LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kenneth D. Church 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 General Manager of Nuclear Fuel Engineering for Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEP?

A. I am responsible for nuclear fuel procurement and spent fuel management, as well as the fuel mechanical design, reactor core design, probabilistic risk assessment, and safety analysis for the nuclear units owned and operated by DEP and DEC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from North Carolina State University with a Bachelor of Science degree in mechanical engineering. I began my career with DEC in 1991 as an engineer and worked in various roles, including nuclear fuel assembly and control component design, fuel performance, and fuel reload engineering. I assumed the commercial responsibility for purchasing uranium, conversion services, enrichment services, and fuel fabrication services at DEC in 2001. Beginning in 2011, I incrementally assumed responsibility at DEC for spent nuclear fuel management along with the nuclear fuel mechanical design and reload licensing analysis functions. Subsequently, I assumed the same responsibilities for DEP following the merger between Duke Energy Corporation and Progress Energy, Inc. before entering my current position in January of 2019.

I have served as Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use, and have also served as Chairman of the World Nuclear Fuel Market's Board of Governors, an organization that promotes efficiencies in the nuclear fuel markets. I am currently a registered professional engineer in the state of North Carolina.

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, 2020 through March 31, 2021 test period ("test period"), and (3) describe changes forthcoming for the December 1, 2021 through November 30, 2022 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 Church Exhibit 1, which is a Graphical Representation of the Nuclear Fuel Cycle, and Church Exhibit 2, which sets forth the Company's Nuclear Fuel Procurement Practices.

Q. PLEASE DESCRIBE THE COMPONENTS THAT MAKE UP 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 Church 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 Church 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 mitigating 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 $43.30 per pound for uranium concentrates during the test period, representing a decrease of 10% per pound 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 average unit cost of DEP's purchases of enrichment services during the test period increased 31% to $100.56 per Separative Work Unit.

Delivered costs for fabrication and conversion services have a limited impact on the overall fuel expense rate given that the dollar amounts for these purchases represent a substantially smaller percentage – 17% and 6%, 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 each represent 43% and 34%, respectively, of the total.

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

A. Prices in the uranium concentrate markets have recently increased due to production cutbacks; however, prices remain relatively low. 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 enrichment and conversion services have recently increased primarily due to a reduction in available inventory supplies.

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. The Company anticipates nuclear fuel costs to remain flat on a cents per kilowatt hour ("kWh") basis through the next billing period. 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 contribute to a portion of the uranium, conversion, enrichment, and fabrication costs reflected in the total fuel expense.

The average fuel expense of 0.587 cents per kWh incurred in the test period is also projected for 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?

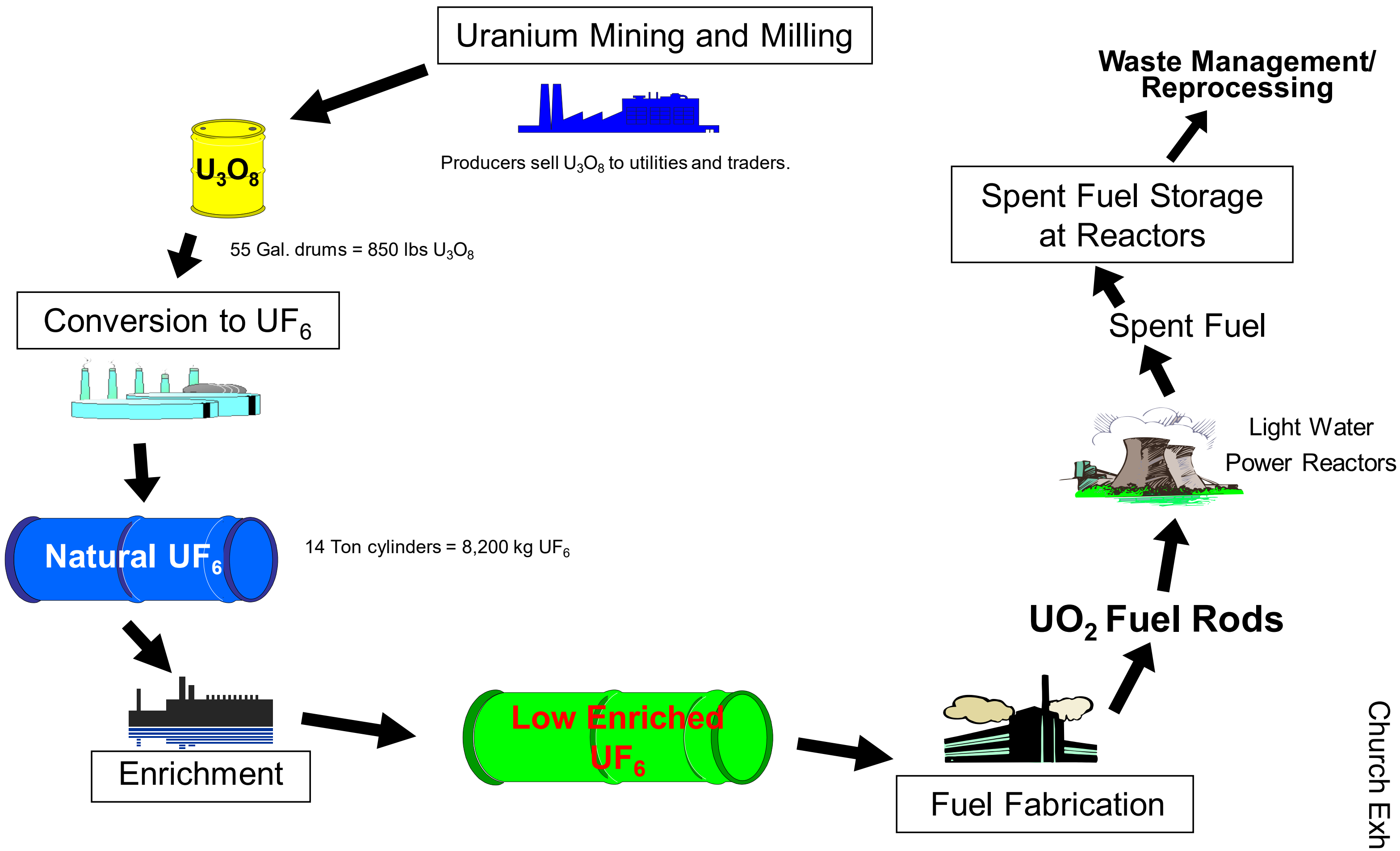
A. As I discussed earlier and as described in Church Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEP relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating 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 mitigating 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.

The Nuclear Fuel Cycle



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 1272

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 19 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 DEC's 2020 fuel and fuel-related cost recovery application in Docket No. E-7, Sub 1250.

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, 2020 through March 31, 2021 ("test period") versus the period April 1, 2019 through March 31, 2020 ("prior test period"), and describe changes projected for the billing period of December 1, 2021 through November 30, 2022 ("billing period").

Q. YOUR TESTIMONY INCLUDES THREE 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 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.

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. HOW DOES DEP OPERATE ITS PORTFOLIO OF GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS?

A. Both DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically committed and dispatched to serve their respective customers. To that end, both companies consider numerous factors such as the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

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 $92.52 per ton, compared to $86.94 per ton in the prior test period, representing an increase of approximately 6%. The cost of delivered coal includes an average transportation cost of $36.75 per ton in the test period, compared to $31.76 per ton in the prior test period, representing an increase of approximately 16%. The cost of delivered coal also includes $12.5 million in costs associated with the mitigation of coal contract obligations related to COVID-19 load losses, as is described in more detail below. The Company's average price of gas purchased for the test period was $3.76 per Million British Thermal Units ("MMBtu"), compared to $3.74 per MMBtu in the prior test period, representing an increase of approximately 1%. The cost of gas is inclusive of gas supply, transportation, storage, and financial hedging.

DEP's coal burn for the test period was 3.4 million tons, compared to a coal burn of 3.6 million tons in the prior test period, representing a decrease of 6%. The Company's natural gas burn for the test period was 157.5 million MBtu, compared to a gas burn of 166.6 million MBtu in the prior test period, representing a decrease of approximately 5%.

As a result of load reduction from the COVID-19 pandemic, extremely low natural gas prices, and mild winter weather, the Company experienced a significant shift in generation from coal to natural gas in the first half of the test period. The COVID-19 pandemic had an unprecedented and unanticipated impact on forecasted spring and summer load in 2020, which in turn reduced coal demand and required inventory mitigation beyond the Company's typical no-cost mitigation measures. Influenced by the operational realities from the pandemic, DEC burned significantly less coal than anticipated, and customers benefited from greater utilization of lower-cost natural gas.

Given the reduction in actual and forecasted coal usage for the balance of 2020, the Company was required to evaluate alternatives to reduce its coal contract obligations for 2020 that exceeded its consumption and storage capabilities. The Company exercised and exhausted its rights to flex down contractual obligations, defer tons, and optimize off-site storage opportunities at no additional cost to the customer in order to address the excess coal due to significant declines in demand related to COVID-19 related shut-downs. After exhausting all of its no-cost contract mitigation options, it was necessary to determine whether to force run coal generation or continue to maximize customers savings by burning natural gas while negotiating to buy out for the remaining balance of its excess 2020 coal obligations. The Company determined through its production cost analysis that pursuing contractual buyouts would result in projected customer savings of approximately $22 million as compared with force running coal generation.

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 due to declining demand for coal stemming from accelerated coal retirements and overall declines in coal generation demand resulting from the impacts of COVID-19 economic shutdowns in 2020; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) changing 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; and, (7) corrections in production levels in an attempt to bring coal supply in balance with demand.

Declining demand for coal in the utility sector is also driving rail transportation providers to modify their business models to be less dependent on coal related transportation revenues. While there remains adequate coal transportation availability, the Company's rail transportation providers have indicated that they will have limited operational flexibility to adapt to significant changes in scheduling demand resulting from the Company's burn volatility, specifically in higher than forecasted coal burn scenarios.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in the short term, such dynamics are influenced primarily by seasonal weather demand and overall storage inventory balances. While there continues to be adequate natural gas production capacity to serve increased market demand, pipeline infrastructure permitting and regulatory process approval efforts are challenged due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing. Specifically, cancellation of the Atlantic Coast Pipeline which was terminated July 5, 2020 will limit the Company's access to low cost natural gas resources.

Over the longer term planning horizon, natural gas supply is projected to continue to increase 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. DEP's current coal burn projection for the billing period is 2.9 million tons, compared to 3.4 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 \$67.06 per ton for the billing period compared to \$92.52 per ton in the test period. This includes an average projected total transportation cost of \$29.07 per ton for the billing period, compared to \$36.75 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 non-Central Appalachian coal DEP is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEP's strong contract compliance monitoring process; (4) changes in transportation rates; 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 current natural gas burn projection for the billing period is approximately 156.7 million MBtu, compared to the 157.5 million MBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.71 per MMBtu, compared to $2.26 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 IMPACTS DOES DEP ANTICIPATE DUE TO THE DECLINES IN EXPECTED COAL BURNS AND CHANGES IN THE ABILITY OF THE RAILROAD TO MEET SIGNIFICANT CHANGES IN COAL DEMAND?

A. Declining flexibility of coal transportation will limit the Company's ability to effectively manage extreme burn volatility. Similarly, the current Fixed/Variable contract in place does not provide ongoing customer value in a declining burn environment. As an alternative to returning to a flat conventional rate structure, the Company is currently negotiating a 100 percent variable tiered pricing contract structure with the goal of achieving a structure that provides incremental customer value to a conventional structure and ensures secure, reliable deliveries in an overall lower coal burn environment.

Q. DOES DEP EXPECT THIS NEW RAIL RATE STRUCTURE TO UTIMATELY IMPACT UNIT COMMITMENT AND DISPATCH?

A. Yes, DEP expects that the tiered pricing structure when incorporated into the Company's unit commitment and dispatch modeling will provide a more predictable coal burn profile while creating potential customer savings over a traditional 100 percent variable conventional rate structure. Effectuating a final contract that is based on a tiered pricing contract structure may also require a more dynamic dispatch methodology.

Q. WHAT OTHER 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.

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. Finally, DEP continues to maintain a short-term financial natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach.

Lastly, DEC procures long-term firm interstate and intrastate transportation to provide natural gas to their 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 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

- Near and long-term coal consumption is forecasted based on inputs such as load projections, 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

- Near and long-term natural gas consumption is forecasted based on inputs such as load projections, 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.

Verderame Exhibit 2
Page 1 of 2

DUKE ENERGY PROGRESS
Summary of Coal Purchases
Twelve Months Ended March 2021 & 2020
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
1	April 2020	205,573	(6,844)	198,729
2	May	37,639	(11,647)	25,992
3	June	13,060	(5,985)	7,075
4	July	205,293	(1,250)	204,043
5	August	280,431	0	280,431
6	September	292,974	0	292,974
7	October	281,434	12,427	293,861
8	November	244,691	24,851	269,542
9	December	293,006	0	293,006
10	January 2021	147,303	74,534	221,837
11	February	195,798	49,231	245,029
12	March	221,728	49,040	270,768
13	**Total** (Sum L1:L12)	**2,418,930**	**184,357**	**2,603,287**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
14	April 2019	323,887	130,272	454,159
15	May	274,199	114,353	388,552
16	June	264,904	128,425	393,329
17	July	302,124	103,008	405,132
18	August	242,562	138,879	381,441
19	September	250,947	122,036	372,983
20	October	328,185	0	328,185
21	November	423,513	12,789	436,302
22	December	388,247	0	388,247
23	January 2020	292,138	51,142	343,280
24	February	0	0	0
25	March	63,516	25,179	88,695
26	**Total** (Sum L14:L25)	**3,154,222**	**826,083**	**3,980,305**

DUKE ENERGY PROGRESS
Summary of Gas Purchases
Twelve Months Ended March 2021 & 2020
MBTUs

Line No.	Month	MBTUs
1	April 2020	8,048,333
2	May	10,825,017
3	June	13,181,648
4	July	17,709,068
5	August	15,791,691
6	September	12,396,157
7	October	11,455,652
8	November	11,887,528
9	December	17,038,827
10	January 2021	15,211,307
11	February	12,301,205
12	March	11,672,834
13	**Total** (Sum L1:L12)	**157,519,267**

Line No.	Month	MBTUs
14	April 2019	12,297,990
15	May	8,937,450
16	June	12,847,001
17	July	15,401,771
18	August	15,584,187
19	September	14,570,973
20	October	13,869,892
21	November	14,862,032
22	December	13,958,980
23	January 2020	15,791,889
24	February	15,640,418
25	March	12,804,810
26	**Total** (Sum L14:L25)	**166,567,393**

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

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 15, 2021

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

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	)	**BEN WALDREP 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 Ben Waldrep 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 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's degree in Nuclear Engineering from Georgia Institute of Technology, a Master's in Business Administration from the University of Phoenix, and I earned a CERT Certificate in Cybersecurity Oversight from Carnegie Mellon

University. I have over 30 years of experience in the nuclear industry, beginning my career at Florida Power & Light's Turkey Point Nuclear Station where I earned a senior reactor operator certification. In 1999, I joined Progress Energy where I held multiple positions of increasing responsibility and served as site vice president at both the Harris and Brunswick nuclear plants. Following the merger of Duke Energy and Progress Energy in 2012, I served as the vice president of corporate governance and operations support for Duke Energy's nuclear fleet, and later was promoted to senior vice president and chief security officer for the enterprise. In the chief security officer role, I was responsible for maintaining Duke Energy's physical and cyber security. In December 2020, I assumed my current role of senior vice president nuclear operations.

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, 2020 through March 31, 2021 (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, 2021 through November 30, 2022 ("billing period").

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

A. Waldrep Exhibit 1 is a confidential exhibit outlining the planned schedule for refueling outages for DEP's nuclear units for the period of April 1, 2021 through November 30, 2022. 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, 2021.

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 49.7% of the total power generated by DEP.

The four nuclear units operated at an actual system average capacity factor of 93.55% during the test period, which included two refueling outages.

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"). The Commission has adopted the NERC standard by rule in evaluating fuel factors in proceedings such as this. The most recently published NERC Brochure indicates an industry average capacity factor of 93.18% for comparable units for the five-year period of 2015 through 2019. The Company's test period capacity factor of 93.55% 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 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 based on experience. 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 this standard, and measures itself against, that schedule. 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 aggressively 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 and, using the benefit of hindsight, identifies 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. IS 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 completed during the test period: Robinson in the fall of 2020 followed by Brunswick Unit 2 during the spring of 2021.

Robinson was disconnected from the grid for refueling on November 7, 2020. Maintenance activities, safety and reliability enhancements, and testing and inspections were completed as the unit was refueled. Large pump and motor maintenance included the replacement of the B heater drain and B condensate pumps. Both the heater drain and condensate pump motors were refurbished, and the B main feed pump was overhauled. Cleaning, plug replacement and testing was completed on the A condenser water box, and the A component cooling water heat exchanger was cleaned and inspected. Electrical A train maintenance included governor replacement on the A emergency diesel generator, installation of a permanent temporary power panel within containment which will reduce time and resources for future outages, and 115KV and 230KV switchyard construction changes supporting more flexibility in scheduling some work online verses during outage periods. Testing and inspection activities included steam generator Eddy Current testing, containment vessel liner panel inspections, and containment integrated leak rate (ILRT) and structural integrity tests. The containment structural integrity tests and ILRT support license renewal. After refueling, maintenance, and testing and inspections completed, the unit returned to service on December 9, 2020. The outage was completed within budget and with the lowest refueling outage dose for the station. The outage extended 15 hours beyond the allocation, primarily driven by emergent challenges with containment sump level and rod control malfunctions.

The Brunswick Unit 2 spring 2021 refueling outage began on March 5, 2021. In addition to refueling, maintenance activities, safety and reliability enhancements, and testing and inspections were completed. Maintenance activities completed during the outage included replacement of the 2A and 2B reactor recirculation pump seals, multiple cryogenic tubing couplings, and replacement of the valve motor operator on the residual heat removal inboard shutdown cooling suction isolation valve. After 45 years of service, the unit's startup auxiliary transformer was replaced. Other activities included the replacement of five safety relief valve main body assemblies and four source range monitor dry tubes. The unit's manual no load disconnect switch (NLDS) was replaced with an electronically operated generator circuit breaker. The replacement of the NLDS with a circuit breaker increases the operability margin and improves reliability of the electrical system. The Brunswick Unit 1 generator was removed from the grid for just under 2 days during 2020 due to challenges with that unit's switch, and the Unit 1 NLDS is scheduled to be replaced with a breaker during the spring 2022 refueling outage. To ensure reliability of Unit 2'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 2A and 2B low-pressure turbines, the reactor core isolation cooling system, the east moisture separator reheater, and the nuclear service water header. The outage was successfully completed with no personnel injuries nor reportable environmental events and represented the lowest radiation dose ever recorded for a Brunswick Unit 2 refueling outage. The unit returned to service on April 5, 2021[2] ; a duration of 30.2 days compared to a scheduled allocation of 33 days.

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 93.21% 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 93.18% for comparable units as reported in the NERC Brochure during the period of 2015 to 2019.

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

A. Yes, it does.

[2] The refueling outage ended 4 days beyond the current review period.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

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	)

BEN WALDREP CONFIDENTIAL EXHIBIT 1

FILED UNDER SEAL

JUNE 15, 2021

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

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	)	**BRYAN P. WALSH 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 Bryan P. Walsh and 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 Services and Organizational Effectiveness 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" or the "Company") and Duke Energy Progress, LLC ("DEP").

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. 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 SERVICES AND ORGANIZATIONAL EFFECTIVENESS?

A. In this role, I am responsible for providing engineering, environmental compliance planning, generation and regulatory strategy, 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. No, I have not testified before this Commission.

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 2020 fuel and fuel-related 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 test period of April 1, 2020 through March 31, 2021 (the "test period"), (3) provide information on significant Fossil/Hydro/Solar outages that occurred during the test period, and (4) provide information concerning environmental compliance efforts.

Q. PLEASE DESCRIBE DEP'S FOSSIL/HYDRO/SOLAR GENERATION PORTFOLIO.

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 ("FGD" or "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") units, the larger 14 of which provide 2,148 MWs, or 89% of CT capacity. These 14 units are located at Asheville, Darlington, Richmond County, and Wayne County facilities, and are equipped with water injection systems that reduce NO_x and/or have low NO_x burner equipment in use. The 3,054 MWs shown as "Combined Cycle Turbines" ("CC") represent six power blocks. The H. F. Lee

[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 141 MWs.

Energy Complex CC power block ("Lee CC") 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 ("Sutton CC") consists of two CTs and one steam turbine. The Asheville Combined Cycle Plant consist of two blocks with a configuration of one CT and one steam turbine each. The six CC power blocks are equipped with SCR equipment, and all eleven CTs have low NOx burners. 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 dependable capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEP'S 2019 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. Darlington CT Units 1, 2, 3, 4, 6, 7, 8, and 10 were retired in March 31, 2020.

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.

The Company complies with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability for customers. 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 in order to prepare the unit for reliable operation until the next planned outage in order to maximize value for customers.

Q. WHAT IS HEAT RATE?

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.

Q. WHAT HAS BEEN THE HEAT RATE OF DEP'S COAL UNITS DURING THE TEST PERIOD?

A. Over the review period, the Company's coal units produced 25% of the Fossil/Hydro/Solar generation, with the average heat rate for the coal-fired units being 11,495 Btu/kWh. The most active station during this period was Roxboro, providing 85% of the coal production for the fleet with a heat rate of 11,030 Btu/kWh. During the review period, the Company's combined cycle power blocks produced 66% of the Fossil/Hydro/Solar generation, with an average heat rate of 7,159 Btu/kWh.

Q. HOW MUCH GENERATION DID EACH TYPE OF FOSSIL/HYDRO/SOLAR GENERATING FACILITY PROVIDE FOR

THE TEST PERIOD AND HOW DOES DEP UTILIZE EACH TYPE OF GENERATING FACILITY TO SERVE CUSTOMERS?

A. For the review period, DEP's total system generation was 59,266,961 megawatt-hours ("MWHs"), of which 29,821,760 MWHs, or approximately 50%, was provided by the Fossil/Hydro/Solar fleet. The breakdown includes a 36% contribution from gas facilities, 13% contribution from coal-fired stations, 1.6% contribution from hydro facilities, and 0.4% from solar facilities.

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. Additionally, DEP has utilized the Joint Dispatch Agreement with Duke Energy Carolinas, LLC ("DEC"), which allows generating resources for DEP and DEC to be dispatched as a single system to enhance dispatching at the lowest possible cost. 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. HOW DID DEP COST EFFECTIVELY DISPATCH ITS DIVERSE MIX OF GENERATING UNITS DURING THE TEST PERIOD?

A. The Company, like other utilities across the U.S., has experienced a change in the dispatch order for each type of generating facility due to continued favorable economics resulting from the lower pricing of natural gas. Further, the addition of new CC units within DEP's 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. These factors promote the use of natural gas and provide real benefits in cost of fuel and reduced emissions for customers. Gas fired facilities provided 71% of the DEP Fossil/Hydro/Solar generation during the review period.

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DEP'S FOSSIL/HYDRO/SOLAR FLEET DURING THE TEST 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) equivalent forced outage rate ("EFOR"), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and, (4) starting reliability ("SR"), which represents the percentage of successful starts. For 2021, the Company is including another measure to assess plant reliability—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 ("NERC Brochure") representing the period 2015 through 2019. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating.

Generator Type	*Measure*	*Review Period DEP Operational Results*	*2015-2019 NERC Average*	*Nbr of Units*
Coal-Fired Test Period	EAF	61.6%	80.1%	188
	NCF	26.7%	55.7%	
	EFOF	10.2%	n/a	
Coal-Fired Summer Peak	EAF	75.6%	n/a	n/a
Total CC Average	EAF	79.1%	84.9%	350
	NCF	62.6%	54.8%	
	EFOR	3.9%	4.9%	
Total CT Average	EAF	83.6%	86.9%	746
	SR	99.3%	98.4%	
Hydro	EAF	70.2%	79.9%	1,060
Solar	NCF	19.7%	n/a	n/a

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

Roxboro Unit 1 had a Spring outage, the primary purpose of the outage was to complete the Dry Fly Ash Tie-in. Roxboro Unit 2 had a planned outage in Spring 2020. The primary purpose of the outage was for a major boiler outage, upgrade control systems, high-energy piping inspection, and control valve restoration. Roxboro Unit 4 has a planned outage in the Spring 2020. This outage was conducted to replace ductwork and high-energy piping inspection. Mayo Unit 1 had a maintenance outage in Fall 2020. The outage scope included scrubber spread header repairs, mist eliminator tray cleaning and spray nozzle replacements, burner repairs, SCR cleanings, and repairs to Air Heater baskets. Roxboro Unit 3 has a planned outage in the Fall 2020. During this outage, the SCR catalyst layer was replaced, boiler waterwall tubes were repaired and high energy piping inspections took place.

Asheville CC had spring transmission outages to relocate transmission lines and perform necessary warranty work.

The CT fleet performed planned outages on Darlington CT 12 and CT 13 in the Fall of 2020. During these outages, turbine control hardware and software systems were replaced.

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, in order 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, as a result 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 Mercury and Air Toxics Standards ("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 THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.