Jack E. Jirak
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June 9, 2020

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 1250

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 Regis Repko, Kenneth D. Church, Kelvin Henderson and Brett Phipps containing the information required in NCUC Rule R8-55.

Certain information contained in the exhibits of Mr. Phipps and Mr. Henderson 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 1250, 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 9th day of June, 2020.

Jack E. Jirak
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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

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

3. NCUC Rule R8-55 provides that the Commission shall schedule annual hearings pursuant to N.C. Gen. Stat. § 62-133.2 in order to review changes in the cost of fuel and fuel-related costs since the last general rate case for each utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service. Rule R8-55 schedules an annual cost of fuel and fuel-related costs adjustment hearing for DEP and requires that the Company use a test period of 12 months ended March 31. Therefore, the test period used in this Application for these proceedings is April 1, 2019 – March 31, 2020 ("test period").

4. In Docket No. E-2, Sub 1204, 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	2.326¢ per kWh
Small General Service	2.499¢ per kWh
Medium General Service	2.456¢ per kWh
Large General Service	2.054¢ per kWh
Lighting	2.217¢ per kWh

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

Residential	2.081¢ per kWh
Small General Service	2.127¢ per kWh
Medium General Service	2.229¢ per kWh
Large General Service	2.204¢ per kWh
Lighting	1.394¢ per kWh

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

Residential	0.180¢ per kWh
Small General Service	0.049¢ per kWh
Medium General Service	0.096¢ per kWh
Large General Service	0.267¢ per kWh
Lighting	0.381¢ per kWh

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

Residential	2.261¢ per kWh
Small General Service	2.176¢ per kWh
Medium General Service	2.325¢ per kWh
Large General Service	2.471¢ per kWh
Lighting	1.775¢ per kWh

The new fuel factors should become effective for service on or after December 1, 2020.

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, Kelvin Henderson, Brett Phipps, Regis Repko, 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 92.72% using projected billing period sales, and based on the proposed nuclear capacity factor of 94.46% using normalized test period sales. These base fuel and fuel-related costs factors are:

	NERC Average	Normalized Sales
Residential	2.336¢ per kWh	2.279¢ per kWh
Small General Service	2.266¢ per kWh	2.195¢ per kWh
Medium General Service	2.385¢ per kWh	2.359¢ per kWh
Large General Service	2.511¢ per kWh	2.466¢ per kWh
Lighting	1.942¢ per kWh	1.738¢ 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	2.261¢ per kWh
Small General Service	2.176¢ per kWh
Medium General Service	2.325¢ per kWh
Large General Service	2.471¢ per kWh
Lighting	1.775¢ per kWh

Respectfully submitted this 9th day of June, 2020.

By:________________________
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ATTORNEYS FOR DUKE ENERGY PROGRESS, LLC

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	DOCKET NO. E-2, SUB 1250
COUNTY OF MECKLENBURG	)	

Dana M. Harrington, bring 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: June 4, 2020

Peggy Holton
Official Signature of Notary

(Official Seal)

PEGGY HOLTON
NOTARY
PUBLIC
WAKE COUNTY, NC

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

My commission expires: 12/22/2021

I signed this notarial certificate on June 4, 2020 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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

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 one year.

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.

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, 2019 through March 31, 2020 ("test period"), and the billing period is December 1, 2020 through November 30, 2021 ("billing period").

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

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

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

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

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

- Exhibit 1: Summary Comparison of Fuel and Fuel-Related Costs Factors.
- Exhibit 2, Schedule 1: Fuel and Fuel-Related Costs Factors - reflecting a 94.46% proposed nuclear capacity factor and projected billing period megawatt hour ("MWh") sales.
- Exhibit 2, Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 94.46%

proposed nuclear capacity factor and normalized test period MWh sales.

- Exhibit 2, Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting an 92.72% 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 2020 Monthly Fuel Report, as required by NCUC Rule R8-52.
- Exhibit 6, Report 2: March 2020 Monthly Base Load Power Plant Performance Report, as required by NCUC Rule R8-53.

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

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

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

A. The Company proposes that the fuel and fuel-related costs factors shown in the table below be reflected in rates during the billing period. The factors that DEP proposes in this proceeding utilize a 94.46% nuclear capacity factor as testified to by Company witness Henderson. 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	2.081	2.127	2.229	2.204	1.394
EMF Increment/(Decrement)	0.180	0.049	0.096	0.267	0.381
Proposed Net Fuel and Fuel-Related Costs Factors	2.261	2.176	2.325	2.471	1.775

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 4.0%, 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	2.261	2.176	2.325	2.471	1.775
Approved Net Fuel and Fuel-Related Costs Factors	2.699	2.697	2.674	2.702	2.747

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

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

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

A. Exhibit 2 is divided into three schedules. Schedule 1 presents the prospective fuel and fuel-related costs. The calculation uses the nuclear capacity factor of 94.46%, as explained in Company witness Henderson's testimony, and provides the projected MWh sales for the billing period on which system generation and costs are based. Schedule 2 also uses the proposed nuclear capacity factor of 94.46% 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 1142).

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 92.72%. This capacity factor is based on the 2014 through 2018 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 production demand, which is serving as a proxy for the production plant allocator. The production plant allocator was approved for use in DEP's most recent general rate case but the prior year factor is unavailable at this time. The Company will apply the production plant allocator to renewable and qualifying facility capacity costs for the purpose of determining the billing period over or under collection, and when the allocator becomes available, should the difference between the production demand allocator and the production plant allocator have a material impact on the proposed rates by class, a supplemental update will be made to revise the proposed rates.

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 92.72% NERC nuclear capacity factor compared to the proposed 94.46% 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 2019 fuel and fuel-related cost recovery proceeding under Docket No. E-2, Sub 1204.

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 2019 production demand allocator. The Company will apply the production plant allocator to these costs for the purpose of determining the billing period over or under collection. When the allocator becomes available, should the difference between the production demand allocator and the production plant allocator have a material impact on the proposed rates in this filing, a supplemental update will be made to revise the proposed rates.

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 4.0% was calculated by dividing the fuel and fuel-related cost decrease of $141 million for the North Carolina retail jurisdiction by the normalized annual North Carolina retail revenues at the existing rates of $3.5 billion. The cost decrease of $141 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 2019, 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 a decrease.

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 $95.4 million for the combined customer classes of the North Carolina retail jurisdiction.

In the 2019 fuel proceeding, Docket E-2, Sub 1204, the Company filed Supplemental Testimony to update the fuel and fuel-related under-recovered balance to include the months of April 2019 through June 2019 in the EMF request in accordance with NCUC Rule R8-55(d)(3). The $41.5 million under-recovery incurred from April 2019 through June 2019 was approved for recovery in the current EMF rate; therefore, the outstanding under-recovery for the test period, representing the under-recovery incurred during the months of July 2019 through March 2020, is $53.9 million.

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 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.

Q. IS THE COMPANY PROPOSING ANY COST ADJUSTMENTS TO THE NINE-MONTH TEST PERIOD UNDER-COLLECTION OF FUEL AND FUEL-RELATED COSTS?

A. Yes. As previously requested in Docket E-2, Sub 1204 and pending the Commission's decision on the issue, the Company has included North Carolina's retail share of $7.3

million in liquidated damages payments and satisfaction for judgment payment in the Total Adjusted Under Recovery Request in this case of $64.9 million as shown on Harrington Exhibit 3 Page 1 of 6. The prior year test period costs are further itemized by customer class on Harrington Exhibit 3 Pages 2 through 6.

In addition, consistent with its request in Docket E-2, Sub 1204, the Company is proposing to recover the related component of net gain/loss on the sale of by-products 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 $(1.7) 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 pending the Commission's decision in Docket No. E-2, Sub 1204.

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 2.504 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 Repko discusses the performance of the fossil/hydro/solar fleet, as well as the chemicals that DEP uses to reduce emissions. Company witness Phipps discusses fossil fuel costs and fossil fuel procurement strategies, and Company witness Church discusses nuclear fuel costs and nuclear fuel procurement strategies. Company witness Henderson discusses the performance of DEP's nuclear generation fleet. While the Company's test year capacity factor and two-year simple average capacity factor were below the five-year national weighted average capacity factor, witness Henderson 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 the request for collection of an approximate $64.9 million under-collection via the proposed EMF increment, compared to the $143.8 million under-collection included in the existing EMF increment. The second largest contributor is declining fuel prices.

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

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

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

A. Yes, it does.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Summary Comparison of Fuel and Fuel-Related Cost Factors
Twelve Months Ended March 31, 2020
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

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 1204)						
1	Approved Fuel and Fuel-Related Costs Factors	Input	2.326	2.499	2.456	2.054	2.217
2	EMF Increment / (Decrement)	Input	0.373	0.198	0.218	0.648	0.530
3	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
4	Approved Net Fuel and Fuel-Related Costs Factors	Sum	2.699	2.697	2.674	2.702	2.747
	Other Fuel and Fuel-Related Cost Factors						
5	NERC Capacity Factor of 92.72% with Projected Billing Period MWh Sales	Exh 2 Sch 3 pg 3	2.336	2.266	2.385	2.511	1.942
6	Proposed Nuclear Capacity Factor of 94.46% with Normalized Test Period MWh Sales	Exh 2 Sch 2 pg 3	2.279	2.195	2.359	2.466	1.738
	Proposed Fuel and Fuel-Related Cost Factors using Proposed Nuclear Capacity Factor of 94.46% with Projected Billing Period MWh Sales						
7	Fuel and Fuel-Related Costs excluding Purchased Capacity	Exh 2 Sch 1 pg 2	1.939	2.007	2.132	2.147	1.394
8	Renewable and Qualifying Facilities Purchased Power Capacity	Exh 2 Sch 1 pg 2	0.142	0.120	0.097	0.057	-
9	Total adjusted Fuel and Fuel-Related Costs Factors	Sum	2.081	2.127	2.229	2.204	1.394
10	EMF Increment/(Decrement)	Exh 2 Sch 1 pg 2	0.180	0.049	0.096	0.267	0.381
11	EMF Interest Decrement, if applicable	n/a	-	-	-	-	-
12	Proposed Net Fuel and Fuel-Related Costs Factors	Exh 2 Sch 1 pg 2	2.261	2.176	2.325	2.471	1.775

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

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.46% with Projected Billing Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 3-4	29,730,338	0.6204	$ 184,443,928
2	Coal	Workpaper 3 - 4	7,940,674	3.0592	242,921,665
3	Gas - CT and CC	Workpaper 3 - 4	18,943,545	2.5883	490,311,290
4	Reagents & Byproducts	Workpaper 5	-		20,467,213
5	Total Fossil	Sum of Lines 2 - 4	26,884,219		753,700,168
6	Hydro	Workpaper 3	650,353		-
7	Net Pumped Storage		-		-
8	Total Hydro	Sum of Lines 6 - 7	650,353		-
9	Utility Owned Solar Generation	Workpaper 3	256,176		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	57,521,087		938,144,096
11	Purchases	Workpaper 3 - 4	9,918,206		464,539,663
12	JDA Savings Shared	Workpaper 5	-		(6,373,541)
13	Total Purchases	Sum of Lines 11 - 12	9,918,206		458,166,122
14	Total Generation and Purchases	Line 10 + Line 13	67,439,293		1,396,310,218
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(4,048,662)		(82,750,327)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,906,330)		-
					-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16	-		$ 1,313,559,891
18	Projected System MWh Sales for Fuel Factor	Workpaper 3	61,484,301		61,484,301
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 /Line 18 / 10			2.136

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.46% with Projected Billing Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Projected Billing Period MWh Sales	Workpaper 8	16,171,290	1,784,993	10,287,749	9,128,353	377,978	37,750,364
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 26,962,441
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,344,300
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 66,306,741
5	NC Portion - Jurisdictional % based on Production Demand Allocator	Workpaper 14						60.68%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 40,233,313
7	Production Demand Allocation Factors	Workpaper 14	56.91%	5.34%	24.89%	12.87%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Demand %	Line 6 * Line 7	$ 22,894,920	$ 2,146,580	$ 10,014,919	$ 5,176,894	$ -	$ 40,233,313
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.142	0.120	0.097	0.057	-	0.107
	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	1.939	2.007	2.132	2.147	1.394	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.142	0.120	0.097	0.057	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.081	2.127	2.229	2.204	1.394	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.180	0.049	0.096	0.267	0.381	
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	2.261	2.176	2.325	2.471	1.775	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.46% with Projected Billing Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Rate Class	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 1204 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	16,171,290	$	1,782,445,149	$	(70,880,727)	-4.0%	(0.438)	2.699	2.261
2	Small General Service	1,784,993		233,805,982		(9,297,530)	-4.0%	(0.521)	2.697	2.176
3	Medium General Service	10,287,749		902,487,703		(35,888,332)	-4.0%	(0.349)	2.674	2.325
4	Large General Service	9,128,353		529,838,208		(21,069,550)	-4.0%	(0.231)	2.702	2.471
5	Lighting	377,978		92,358,220		(3,672,718)	-4.0%	(0.972)	2.747	1.775
6	NC Retail	37,750,364	$	3,540,935,260	$	(140,808,857)				

Line No.	Description	Source		Amount
	Total Proposed Composite Fuel Rate:			
7	Adjusted System Total Fuel Costs	Workpaper 8	$	1,314,547,846
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2		66,306,741
9	Adjusted System Other Fuel Costs	Line 7 - Line 8	$	1,248,241,105
10	NC Retail Allocation % - sales at generation	Workpaper 11		61.59%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$	768,791,697
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2		40,233,313
13	NC Retail Total Fuel Costs before 2.5% Purchase Power Test	Line 11 + Line 12	$	809,025,010
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16		0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$	809,025,010
16	NC Projected Billing Period MWh Sales	Line 6, col A		37,750,364
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 / 10		2.143
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		0.171
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		2.314
	Total Current Composite Fuel Rate - Docket E-2 Sub 1204:			
21	Current composite Fuel Rate cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17		2.306
22	Current composite EMF Rate cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18		0.381
23	Current composite EMF Interest cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19		0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21-23		2.687
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24		(0.373)
26	NC Projected Billing Period MWh Sales	Line 6, col A		37,750,364
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$	(140,808,857)

Notes:
Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.46% with Normalized Test Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 3-4	29,730,338	0.6204	$	184,443,928
2	Coal	Workpaper 15	8,861,608	3.0592		271,094,943
3	Gas - CT and CC	Workpaper 3-4	18,943,545	2.5883		490,311,290
4	Reagents & Byproducts	Workpaper 4	-			20,467,213
5	Total Fossil	Sum of Lines 2 - 4	27,805,153			781,873,446
6	Hydro	Workpaper 3	650,353			-
7	Net Pumped Storage		-			-
8	Total Hydro	Sum of Lines 6 - 7	650,353			-
9	Utility Owned Solar Generation	Workpaper 3	256,176			-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	58,442,021			966,317,374
11	Purchases	Workpaper 3 - 4	9,918,206			464,539,663
12	JDA Savings Shared	Workpaper 5	-			(6,373,541)
13	Total Purchases	Sum of Lines 11 - 12	9,918,206			458,166,122
14	Total Generation and Purchases	Line 10 + Line 13	68,360,227			1,424,483,496
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(4,048,662)			(82,750,327)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,935,872)			-
						-
17	System Fuel Expense for Fuel Factor	Lines 14 + Line 15 + Line 16	-		$	1,341,733,169
18	Normalized Test Period MWh Sales for Fuel Factor	Exhibit 4	62,375,693			62,375,693
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10				2.151

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.46% with Normalized Test Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Normalized Test Period MWh Sales	Workpaper 9	16,191,429	1,777,668	10,949,334	8,584,996	349,444	37,852,870
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 26,962,441
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,344,300
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 66,306,741
5	NC Portion - Jurisdictional % based on Production Demand Allocator	Input						60.68%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 40,233,313
7	Production Demand Allocation Factors	Workpaper 14	56.91%	5.34%	24.89%	12.87%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Demand %	Line 6 * Line 7	$ 22,894,920	$ 2,146,580	$ 10,014,919	$ 5,176,894	$ -	$ 40,233,313
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.141	0.121	0.091	0.060	-	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	1.958	2.025	2.172	2.139	1.357	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.141	0.121	0.091	0.060	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.099	2.146	2.263	2.199	1.357	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.180	0.049	0.096	0.267	0.381	
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	2.279	2.195	2.359	2.466	1.738	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.46% with Normalized Test Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Rate Class	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 1204 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	16,191,429	$ 1,782,445,149	$ (68,024,478)	-3.8%	(0.420)	2.699	2.279
2	Small General Service	1,777,668	233,805,982	(8,922,872)	-3.8%	(0.502)	2.697	2.195
3	Medium General Service	10,949,334	902,487,703	(34,442,157)	-3.8%	(0.315)	2.674	2.359
4	Large General Service	8,584,996	529,838,208	(20,220,520)	-3.8%	(0.236)	2.702	2.466
5	Lighting	349,444	92,358,220	(3,524,720)	-3.8%	(1.009)	2.747	1.738
6	NC Retail	37,852,870	$ 3,540,935,260	$ (135,134,747)				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 9	$ 1,342,721,124
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	66,306,741
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,276,414,383
10	NC Retail Allocation % - sales at generation	Workpaper 11	60.88%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 777,081,077
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	40,233,313
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 817,314,390
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 17	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 817,314,390
16	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A	37,852,870
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.159
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.171
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	2.330
	Total Current Composite Fuel Rate - Docket E-2 Sub 1204:		
21	Current composite Fuel Rate cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17	2.306
22	Current composite EMF Rate cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18	0.381
23	Current composite EMF Interest cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.687
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.357)
26	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A	37,852,870
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$ (135,134,747)

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 92.72% with Projected Billing Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 2	28,123,601	0.6204	$ 174,475,894
2	Coal	Workpaper 15	9,547,412	3.0592	292,075,099
3	Gas - CT and CC	Workpaper 3 - 4	18,943,545	2.5883	490,311,290
4	Reagents & Byproducts	Workpaper 5	-		20,467,213
5	Total Fossil	Sum of Lines 2 - 4	28,490,957		802,853,602
6	Hydro	Workpaper 3	650,353		-
7	Net Pumped Storage		-		-
8	Total Hydro	Sum of Lines 6 - 7	650,353		-
9	Utility Owned Solar Generation	Workpaper 3	256,176		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	57,521,087		977,329,497
11	Purchases	Workpaper 3 - 4	9,918,206		464,539,663
12	JDA Savings Shared	Workpaper 5	-		(6,373,541)
13	Total Purchases	Sum of Lines 11- 12	9,918,206		458,166,122
14	Total Generation and Purchases	Line 10 + Line 13	67,439,293		1,435,495,619
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(4,048,662)		(82,750,327)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,906,330)		-
					-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16	-		$ 1,352,745,292
18	System MWh Sales for Fuel Factor	Workpaper 3	61,484,301		61,484,301
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10			2.200

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 92.72% with Projected Billing Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Projected Billing Period MWh Sales	Workpaper 8	16,171,290	1,784,993	10,287,749	9,128,353	377,978	37,750,364
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 26,962,441
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,344,300
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 66,306,741
5	NC Portion - Jurisdictional % based on Production Demand Allocator	Input						60.68%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 40,233,313
7	Production Demand Allocation Factors	Workpaper 14	56.91%	5.34%	24.89%	12.87%	0.00%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Demand %	Line 6 * Line 7	$ 22,894,920	$ 2,146,580	$ 10,014,919	$ 5,176,894	$ -	$ 40,233,313
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.142	0.120	0.097	0.057	-	0.107
	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	2.014	2.097	2.192	2.187	1.561	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.142	0.120	0.097	0.057	-	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.156	2.217	2.289	2.244	1.561	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.180	0.049	0.096	0.267	0.381	
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	2.336	2.266	2.385	2.511	1.942	

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 92.72% with Projected Billing Period MWh Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Rate Class	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 1204 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	16,171,290	$ 1,782,445,149	$ (58,718,886)	-3.3%	(0.363)	2.699	2.336
2	Small General Service	1,784,993	233,805,982	(7,702,244)	-3.3%	(0.431)	2.697	2.266
3	Medium General Service	10,287,749	902,487,703	(29,730,549)	-3.3%	(0.289)	2.674	2.385
4	Large General Service	9,128,353	529,838,208	(17,454,399)	-3.3%	(0.191)	2.702	2.511
5	Lighting	377,978	92,358,220	(3,042,546)	-3.3%	(0.805)	2.747	1.942
6	NC Retail	37,750,364	$ 3,540,935,260	$ (116,648,624)				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 10	$ 1,353,733,247
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	66,306,741
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,287,426,506
10	NC Retail Allocation % - sales at generation	Workpaper 11	61.59%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 792,925,985
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	40,233,313
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 833,159,298
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 833,159,298
16	NC Projected Billing Period MWh Sales	Line 6, col A	37,750,364
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.207
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.171
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	2.378
	Total Current Composite Fuel Rate - Docket E-2 Sub 1204:		
21	Current composite Fuel Rate cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 17	2.306
22	Current composite EMF Rate cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 18	0.381
23	Current composite EMF Interest cents/kWh	2019 Revised Harrington Exh 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.687
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.309)
26	NC Projected Billing Period MWh Sales	Line 6, col A	37,750,364
27	Increase/(Decrease) in Fuel Costs	Line 25* Line 26 * 10	$ (116,648,624)

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, 2020
Docket No. E-2, Sub 1250

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2019 (Sub 1173)	2.686	2.236	2,728,574	$ 12,291,799	-	$ 12,291,799
2	May	2.782	2.239	2,833,194	15,364,636	-	15,364,636
3	June	2.680	2.249	3,213,527	13,827,917	-	13,827,917
4	July	2.754	2.252	3,688,282	18,528,663	-	18,528,663
5	August	2.735	2.254	3,723,369	17,897,273	-	17,897,273
6	September	2.540	2.249	3,556,134	10,361,598	-	10,361,598
7	October	2.432	2.240	3,108,120	5,957,660	-	5,957,660
8	November	2.896	2.229	2,604,857	17,356,270	-	17,356,270
9	December (New Rates - Sub 1204)	2.307	2.275	3,103,485	988,481	-	988,481
10	January 2020	2.074	2.310	3,148,281	(7,449,740)	-	(7,449,740)
11	February	2.137	2.311	3,069,536	(5,335,053)	-	(5,335,053)
12	March	2.154	2.306	2,878,564	(4,356,037)	-	(4,356,037)
13	Total Test Period			37,655,926	$ 95,433,467	-	$ 95,433,467
14	Booked 12-month (Over) / Under Recovery						$ 95,433,467
15	Adjustment to exclude Under Recovery - April - June 2019 (1)						(41,484,352)
16	Total 9-month (Over) / Under Recovery						$ 53,949,115
17	Adjustment to exclude test period by-product net gain/loss accrued expense, subject to Docket No. E-2 Sub 1204 Commission judgment						(1,651,186)
18	Adjustment to include test period by-product net gain/loss cash payments, subject to Docket No. E-2 Sub 1204 Commission judgment						5,296,291
19	Adjustment to include Docket No. E-2 Sub 1204 costs subject to Commission judgment						7,260,171
20	Total Adjusted (Over) / Under Recovery Request						$ 64,854,391
21	Normalized Test Period MWh Sales	Exhibit 4					37,852,870
22	Experience Modification Increment / (Decrement) cents/KWh						0.171

Notes:
Totals may not foot due to rounding.
(1) April - June 2019 filed in fuel Docket E-2, Sub 1204 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Twelve Months Ended March 31, 2020
Docket No. E-2, Sub 1250

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2019 (Sub 1173)	3.033	2.311	1,060,985	$ 7,664,663		$ 7,664,663
2	May	3.295	2.311	1,051,096	10,340,265		10,340,265
3	June	2.843	2.311	1,331,074	7,081,848		7,081,848
4	July	2.794	2.311	1,602,414	7,741,904		7,741,904
5	August	2.784	2.311	1,612,109	7,629,308		7,629,308
6	September	2.723	2.311	1,460,214	6,009,364		6,009,364
7	October	2.841	2.311	1,166,428	6,177,517		6,177,517
8	November	3.306	2.311	999,969	9,946,288		9,946,288
9	December (New Rates - Sub 1204)	2.207	2.317	1,410,306	(1,556,451)		(1,556,451)
10	January 2020	1.956	2.326	1,438,353	(5,324,375)		(5,324,375)
11	February	2.031	2.326	1,391,776	(4,103,653)		(4,103,653)
12	March	2.160	2.326	1,235,463	(2,055,811)		(2,055,811)
13	Total Test Period			15,760,190	49,550,869	-	49,550,869
14	Booked 12-month (Over) / Under Recovery						$ 49,550,869
15	Adjustment to exclude Under Recovery - April - June 2019 (1)						(25,086,775)
16	Total 9-month (Over) / Under Recovery						$ 24,464,093
17	Adjustment to exclude test period by-product net gain/loss accrued expense, subject to Docket No. E-2 Sub 1204 Commission judgment						(748,674)
18	Adjustment to include test period by-product net gain/loss cash payments, subject to Docket No. E-2 Sub 1204 Commission judgment						2,401,422
19	Adjustment to include Docket No. E-2 Sub 1204 costs subject to Commission judgment						3,080,009
20	Total Adjusted (Over) / Under Recovery Request						$ 29,196,850
21	Normalized Test Period MWh Sales	Exhibit 4					16,191,429
22	Experience Modification Increment (Decrement) cents/KWh						0.180

Notes:

Totals may not foot due to rounding.

(1) April - June 2019 filed in fuel Docket E-2, Sub 1204 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Small General Service
Twelve Months Ended March 31, 2020
Docket No. E-2, Sub 1250

Line No.	Month		Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2019 (Sub 1173)		2.930	2.556	136,059	$ 508,889		$ 508,889
2	May		2.974	2.556	144,225	603,324		603,324
3	June		2.793	2.556	167,849	397,399		397,399
4	July		2.873	2.556	193,031	612,524		612,524
5	August		2.758	2.556	201,636	406,378		406,378
6	September		2.604	2.556	189,089	91,426		91,426
7	October		2.447	2.556	167,741	(183,357)		(183,357)
8	November		3.270	2.556	125,205	894,152		894,152
9	December (New Rates - Sub 1204)		2.451	2.533	154,918	(127,643)		(127,643)
10	January 2020		2.156	2.499	155,579	(533,274)		(533,274)
11	February		2.177	2.499	154,850	(498,540)		(498,540)
12	March		2.249	2.499	141,377	(352,792)		(352,792)
13	Total Test Period				1,931,559	1,818,485	-	1,818,485
14	Booked 12-month (Over) / Under Recovery							$ 1,818,485
15	Adjustment to exclude Under Recovery - April - June 2019 (1)							(1,509,612)
16	Total 9-month (Over) / Under Recovery							$ 308,873
17	Adjustment to exclude test period by-product net gain/loss accrued expense, subject to Docket No. E-2 Sub 1204 Commission judgment							(83,298)
18	Adjustment to include test period by-product net gain/loss cash payments, subject to Docket No. E-2 Sub 1204 Commission judgment							267,184
19	Adjustment to include Docket No. E-2 Sub 1204 costs subject to Commission judgment							375,378
20	Total Adjusted (Over) / Under Recovery Request							$ 868,137
21	Normalized Test Period MWh Sales	Exhibit 4						1,777,668
22	Experience Modification Increment (Decrement) cents/KWh							0.049

Notes:
Totals may not foot due to rounding.
(1) April - June 2019 filed in fuel Docket E-2, Sub 1204 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Medium General Service
Twelve Months Ended March 31, 2020
Docket No. E-2, Sub 1250

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2019 (Sub 1173)	2.697	2.477	827,811	$ 1,817,211		$ 1,817,211
2	May	2.639	2.477	908,898	1,474,141		1,474,141
3	June	2.710	2.477	967,184	2,251,604		2,251,604
4	July	2.893	2.477	1,066,966	4,436,980		4,436,980
5	August	2.849	2.477	1,085,771	4,042,108		4,042,108
6	September	2.555	2.477	1,074,880	843,243		843,243
7	October	2.349	2.477	980,376	(1,250,862)		(1,250,862)
8	November	2.942	2.477	781,506	3,635,799		3,635,799
9	December (New Rates - Sub 1204)	2.526	2.468	849,236	487,730		487,730
10	January 2020	2.235	2.456	851,930	(1,879,357)		(1,879,357)
11	February	2.287	2.456	836,428	(1,410,803)		(1,410,803)
12	March	2.269	2.456	797,215	(1,487,684)		(1,487,684)
13	Total Test Period			11,028,202	12,960,111	-	12,960,111
14	Booked 12-month (Over) / Under Recovery						$ 12,960,111
15	Adjustment to exclude Under Recovery - April - June 2019 (1)						(5,542,956)
16	Total 9-month (Over) / Under Recovery						$ 7,417,155
17	Adjustment to exclude test period by-product net gain/loss accrued expense, subject to Docket No. E-2 Sub 1204 Commission judgment						(449,937)
18	Adjustment to include test period by-product net gain/loss cash payments, subject to Docket No. E-2 Sub 1204 Commission judgment						1,443,204
19	Adjustment to include Docket No. E-2 Sub 1204 costs subject to Commission judgment						2,123,029
20	Total Adjusted (Over) / Under Recovery Request						$ 10,533,450
21	Normalized Test Period MWh Sales	Exhibit 4					10,949,334
22	Experience Modification Increment (Decrement) cents/KWh						0.096

Notes:

Totals may not foot due to rounding.

(1) April - June 2019 filed in fuel Docket E-2, Sub 1204 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Large General Service
Twelve Months Ended March 31, 2020
Docket No. E-2, Sub 1250

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2019 (Sub 1173)	2.086	1.757	674,418	$ 2,215,935		$ 2,215,935
2	May	2.160	1.757	699,442	2,816,304		2,816,304
3	June	2.297	1.757	718,601	3,877,285		3,877,285
4	July	2.436	1.757	796,174	5,404,669		5,404,669
5	August	2.446	1.757	794,681	5,473,681		5,473,681
6	September	2.151	1.757	803,124	3,166,077		3,166,077
7	October	1.902	1.757	763,680	1,111,002		1,111,002
8	November	2.165	1.757	670,112	2,734,527		2,734,527
9	December (New Rates - Sub 1204)	2.196	1.877	660,159	2,102,953		2,102,953
10	January 2020	2.097	2.053	673,577	290,408		290,408
11	February	2.157	2.054	657,799	675,428		675,428
12	March	1.990	2.054	675,674	(430,337)		(430,337)
13	Total Test Period			8,587,442	29,437,932	-	29,437,932
14	Booked 12-month (Over) / Under Recovery						$ 29,437,932
15	Adjustment to exclude Under Recovery - April - June 2019 (1)						(8,909,524)
16	Total 9-month (Over) / Under Recovery						$ 20,528,408
17	Adjustment to exclude test period by-product net gain/loss accrued expense, subject to Docket No. E-2 Sub 1204 Commission judgment						(353,848)
18	Adjustment to include test period by-product net gain/loss cash payments, subject to Docket No. E-2 Sub 1204 Commission judgment						1,134,991
19	Adjustment to include Docket No. E-2 Sub 1204 costs subject to Commission judgment						1,614,722
20	Total Adjusted (Over) / Under Recovery Request						$ 22,924,274
21	Normalized Test Period MWh Sales	Exhibit 4					8,584,996
22	Experience Modification Increment (Decrement) cents/KWh						0.267

Notes:
Totals may not foot due to rounding.
(1) April - June 2019 filed in fuel Docket E-2, Sub 1204 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Lighting
Twelve Months Ended March 31, 2020
Docket No. E-2, Sub 1250

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2019 (Sub 1173)	2.541	2.251	29,301	$ 85,101		$ 85,101
2	May	2.693	2.251	29,533	130,603		130,603
3	June	3.014	2.251	28,819	219,780		219,780
4	July	3.371	2.251	29,697	332,585		332,585
5	August	3.436	2.251	29,171	345,798		345,798
6	September	3.123	2.251	28,826	251,488		251,488
7	October	2.597	2.251	29,896	103,360		103,360
8	November	2.769	2.251	28,066	145,504		145,504
9	December (New Rates - Sub 1204)	2.521	2.237	28,866	81,892		81,892
10	January 2020	2.206	2.217	28,842	(3,142)		(3,142)
11	February	2.226	2.217	28,683	2,515		2,515
12	March	2.115	2.217	28,834	(29,414)		(29,414)
13	Total Test Period			348,533	1,666,070	-	1,666,070
14	Booked 12-month (Over) / Under Recovery						$ 1,666,070
15	Adjustment to exclude Under Recovery - April - June 2019 (1)						(435,484)
16	Total 9-month (Over) / Under Recovery						$ 1,230,586
17	Adjustment to exclude test period by-product net gain/loss accrued expense, subject to Docket No. E-2 Sub 1204 Commission judgment						(15,429)
18	Adjustment to include test period by-product net gain/loss cash payments, subject to Docket No. E-2 Sub 1204 Commission judgment						49,490
19	Adjustment to include Docket No. E-2 Sub 1204 costs subject to Commission judgment						67,033
20	Total Adjusted (Over) / Under Recovery Request						$ 1,331,679
21	Normalized Test Period MWh Sales	Exhibit 4					349,444
22	Experience Modification Increment (Decrement) cents/KWh						0.381

Notes:

Totals may not foot due to rounding.

(1) April - June 2019 filed in fuel Docket E-2, Sub 1204 are included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55 (d)(3) but deducted from total (O)/ U on Line 15.

Duke Energy Progress, LLC **Harrington Exhibit 4**
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, 2020
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

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	61,765,556	37,655,926	15,760,190	1,931,559	11,028,202	8,587,442	348,533
2	Customer Growth MWh Adjustment	Workpaper 9	198,273	88,359	101,073	809	(18,408)	3,976	911
3	Weather MWh Adjustment	Workpaper 9	411,864	108,585	330,167	(154,700)	(60,460)	(6,422)	-
4	Total Adjusted MWh Sales	Sum Lines 1-3	62,375,693	37,852,870	16,191,429	1,777,668	10,949,334	8,584,996	349,444
5	Test Period Fuel and Fuel-Related Revenue *		$ 1,397,284,269	$ 852,009,744					
6	Test Period Fuel and Fuel-Related Expense *		$ 1,557,246,310	$ 947,443,211					
7	Test Period Unadjusted (Over)/Under Recovery	Line 5 - Line 6	$ 159,962,041	$ 95,433,467					

		2019 Winter Coincidental Peak (CP) KW
8	Total System Peak	13,207,703
9	NC Retail	8,014,112
10	NC Residential Peak	4,560,461
11	NC Small General Service	427,579
12	NC Medium General Service	1,994,881
13	NC Large General Service	1,031,190

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, 2020
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Unit	Rate Case Docket E-2, Sub 1142	Fuel Docket E-2, Sub 1204	Proposed Capacity Rating MW
Brunswick 1	938	938	938
Brunswick 2	932	932	932
Harris 1	928	964	964
Robinson 2	741	741	759
Total Company	3,539	3,575	3,593

March 2020
Monthly Fuel Filing and Baseload Report Cover Sheet

Schedule 1

DUKE ENERGY PROGRESS
SUMMARY OF MONTHLY FUEL REPORT

Docket No. E-2, Sub 1225

Line No.	Fuel Expenses:	March 2020	12 Months Ended March 2020
1	Total Fuel and Fuel-Related Costs	$ 97,552,730	$ 1,546,653,740
	MWH sales:		
2	Total System Sales	4,793,325	67,320,898
3	Less intersystem sales	242,171	5,555,343
4	Total sales less intersystem sales	4,551,154	61,765,555
5	Total fuel and fuel-related costs (¢/KWH) (Line 1/Line 4)	2.143	2.504
6	Current fuel & fuel-related cost component (¢/KWH) (per Schedule 4, Line 5a Total)	2.306	
	Generation Mix (MWH):		
	Fossil (By Primary Fuel Type):		
7	Coal	233,017	8,371,720
8	Oil	986	59,067
9	Natural Gas - Combustion Turbine	198,698	2,350,810
10	Natural Gas - Combined Cycle	1,486,370	19,405,345
11	Biogas	1,544	12,032
12	Total Fossil	1,920,615	30,198,973
13	Nuclear	2,006,698	28,861,332
14	Hydro - Conventional	73,324	662,207
15	Solar Distributed Generation	19,038	258,435
16	Total MWH generation	4,019,675	59,980,947

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 1225

Description	March 2020	12 Months Ended March 2020
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0501110 coal consumed - steam	$ 9,364,725	$ 311,732,857
0501310 fuel oil consumed - steam	215,303	6,525,088
Total Steam Generation - Account 501	9,580,028	318,257,945
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	11,643,238	175,626,194
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	5,077,428	90,464,471
0547000 natural gas consumed - Combined Cycle	40,711,781	532,121,009
0547106 biogas consumed - Combined Cycle	70,811	571,723
0547200 fuel oil consumed	23,785	4,305,680
Total Other Generation - Account 547	45,883,805	627,462,883
Reagents		
Catalyst Depreciation	114,923	1,555,239
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	511,642	15,418,914
Total Reagents	626,565	16,974,153
By-products		
Net proceeds from sale of by-products	825,205	11,977,751
Total By-products	825,205	11,977,751
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	68,558,841	1,150,298,926
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (PURPA)	1,566,684	40,857,994
Capacity component of purchased power (renewables)	2,103,735	44,459,825
Fuel and fuel-related component of purchased power	29,257,564	427,271,568
Total Purchased Power and Net Interchange - Account 555	32,927,983	512,589,387
Less:		
Fuel and fuel-related costs recovered through intersystem sales	3,933,994	116,225,906
Solar Integration Charge	100	8,667
Total Fuel Credits - Accounts 447/456	3,934,094	116,234,573
Total Fuel and Fuel-Related Costs	$ 97,552,730	$ 1,546,653,740

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 2020

Schedule 3, Purchases
Page 1 of 4

Purchased Power	Total	Capacity	Non-capacity			
						Not Fuel $
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel-related $
Alcoa Power Marketing Inc.	-	-	-	-	-	
Broad River Energy, LLC.	$ 1,627,028	$ 996,440	10,226	$ 336,614	$ 293,974	
City of Fayetteville	687,231	702,000	-	(14,769)	-	
DE Carolinas - Native Load Transfer	3,278,662	-	193,690	2,826,692	476,361	$ (24,391)
DE Carolinas - Native Load Transfer Benefit	638,770	-	-	638,770	-	
DE Carolinas - Fees	(5,573)	-	-	-	(5,573)	
Haywood EMC	28,550	28,550	-	-	-	
NCEMC	2,872,255	2,635,688	6,663	206,223	30,344	
PJM Interconnection, LLC.	528	-	-	-	528	
Southern Company Services	2,760,936	687,323	94,186	1,700,829	372,784	
	$ 11,888,387	**$ 5,050,001**	**304,765**	**$ 5,694,359**	**$ 1,168,418**	**$ (24,391)**
Renewable Energy						
REPS	$ 13,061,139	-	205,875	-	$ 13,061,139	-
DERP Qualifying Facilities	44,087	-	917	-	44,087	-
	$ 13,105,226	**-**	**206,792**	**-**	**$ 13,105,226**	**-**
HB589 PURPA Purchases						
Qualifying Facilities	$ 12,945,019	-	270,356	-	$ 12,945,019	-
	$ 12,945,019	**-**	**270,356**	**-**	**$ 12,945,019**	**-**
Non-dispatchable						
DE Carolinas - Emergency	$ 11,826	-	500	$ 7,214	-	$ 4,612
Dominion Energy South Carolina - Emergency	5,150	-	103	3,142	-	2,008
Energy Imbalance	4,608	-	270	4,208	-	400
Generation Imbalance	651	-	47	397	-	254
Qualifying Facilities	-	-	-	-	-	-
	$ 22,235	**-**	**920**	**$ 14,961**	**-**	**$ 7,274**
Total Purchased Power	**$ 37,960,867**	**$ 5,050,001**	**782,833**	**$ 5,709,320**	**$ 27,218,663**	**$ (17,117)**

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

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

MARCH 2020

	Total	Capacity	Non-capacity		
Sales	$	$	mWh	Fuel $	Non-fuel $
Market Based:					
NCEMC Purchase Power Agreement	$ 898,429	$ 652,500	9,474	$ 153,777	$ 92,152
PJM Interconnection, LLC.	238,782	-	18,913	279,031	(40,249)
Other:					
DE Carolinas - Native Load Transfer Benefit	$ 546,006	-	-	$ 546,006	-
DE Carolinas - Native Load Transfer	3,130,805	-	213,775	2,955,180	$ 175,625
Generation Imbalance	-	-	9	-	-
Total Intersystem Sales	**$ 4,814,022**	**$ 652,500**	**242,171**	**$ 3,933,994**	**$ 227,528**

* 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 2020

Purchased Power	**Total**	**Capacity**	**Non-capacity**			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Broad River Energy, LLC.	$ 63,826,838	$ 44,358,458	365,707	$ 12,819,480	$ 6,648,900	
City of Fayetteville	13,551,418	12,493,350	16,660	779,150	278,918	
DE Carolinas - Native Load Transfer	38,316,583	-	1,608,874	32,145,110	6,144,973	$ 26,499
DE Carolinas - Native Load Transfer Benefit	4,193,107	-	-	4,193,107	-	
DE Carolinas - Fees	98,267	-	-	-	98,267	
Haywood EMC	362,219	356,383	168	5,836	-	
NCEMC	43,861,751	36,366,933	190,587	6,980,814	514,004	
PJM Interconnection, LLC.	270,556	-	8,237	161,533	109,023	
Southern Company Services	47,215,492	14,213,809	1,223,097	26,600,709	6,400,974	
	$ 211,696,231	**$ 107,788,933**	**3,413,330**	**$ 83,685,739**	**$ 20,195,059**	**$ 26,499**
Renewable Energy						
REPS	$ 219,298,567	-	3,196,429	-	$ 219,298,567	-
DERP Net Metering Excess Generation	16,899	$ 2,915	394	-	-	$ 13,984
DERP Qualifying Facilities	600,306	-	12,314	-	600,306	-
	$ 219,915,772	**$ 2,915**	**3,209,137**	**-**	**$ 219,898,873**	**$ 13,984**
HB589 PURPA Purchases						
Qualifying Facilities	$ 187,902,788	-	3,206,430	-	$ 187,902,788	-
	$ 187,902,788	**-**	**3,206,430**	**-**	**$ 187,902,788**	**-**
Non-dispatchable						
DE Carolinas - Emergency	$ 44,432	-	1,869	$ 27,104	-	$ 17,328
DE Carolinas - Reliability	1,163,688	-	20,232	709,850	-	453,838
Dominion Energy South Carolina - Emergency	5,150	-	103	3,142	-	2,008
Virginia Electric and Power Company - Emergency	43,433	-	1,415	26,358	-	17,075
Energy Imbalance	147,661	-	5,751	137,267	-	10,394
Generation Imbalance	4,656	-	434	3,207	-	1,449
	$ 1,409,020	**-**	**29,804**	**$ 906,928**	**-**	**$ 502,092**
Total Purchased Power	**$ 620,923,811**	**$ 107,791,848**	**9,858,701**	**$ 84,592,667**	**$ 427,996,720**	**$ 542,575**

NOTES: 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 2020

	Total	Capacity	Non-capacity		
Sales	$	$	mWh	Fuel $	Non-fuel $
Utilities:					
DE Carolinas - Emergency	$ 132,012	-	1,452	$ 80,527	$ 51,485
DE Carolinas - As Available Capacity	216,196	$ 216,196	-	-	-
Market Based:					
NCEMC Purchase Power Agreement	$ 11,415,531	$ 7,830,001	113,371	$ 2,901,323	$ 684,206
PJM Interconnection, LLC.	1,321,164	-	66,917	1,234,943	86,220
Other:					
DE Carolinas - Native Load Transfer Benefit	$ 12,206,819	-	-	$ 12,206,819	-
DE Carolinas - Native Load Transfer	105,109,458	-	5,372,692	99,782,117	$ 5,327,342
Generation Imbalance	23,750	-	911	20,177	3,572
Total Intersystem Sales	**$ 130,424,930**	**$ 8,046,197**	**5,555,343**	**$ 116,225,906**	**$ 6,152,825**

* Sales for resale other than native load priority.

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

Schedule 4

DUKE ENERGY PROGRESS
(OVER) / UNDER RECOVERY OF FUEL COSTS
MARCH 2020

Line No.			Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total
1	1a. System Retail kWh sales	Input						4,551,154,460
	1b. System kWh Sales at generation	Input						4,710,432,773
2	2a. DERP Net Metered kWh generation	Input						2,529,301
	2b. Line loss percentage from Cost of Service	Input Annually						3.909%
	2c. DERP Net Metered kWh at generation	L2a * (1 + 2b)						2,628,171
3	Adjusted System kWh sales	L1b + L2c						4,713,060,944
4	4a. N.C. Retail kWh sales	Input	1,235,463,083	141,377,071	797,215,462	675,674,106	28,834,155	2,878,563,877
	4b. Line loss percentage from Cost of Service	Input Annually	4.505%	4.504%	4.332%	3.206%	4.502%	
	4c. NC kWh Sales at generation	4a * (1+4b)	1,291,120,695	147,744,694	831,750,836	697,336,218	30,132,269	2,998,084,712
	4d. NC allocation % by customer class	Calculated	43.065%	4.928%	27.743%	23.259%	1.005%	
	4e. NC retail % of actual system total	L4c NC Total / L1b Total System						63.648%
	4f. NC retail % of adjusted system total	L4c NC Total / L3 Total System						63.612%
5	Approved fuel and fuel-related rates (¢/kWh)							
	5a Billed rates by class (¢/kWh)	Input Annually	2.326	2.499	2.456	2.054	2.217	2.306
	5b Billed fuel expense	L4a * L5a / 100	$28,736,871	$3,533,013	$19,579,612	$13,878,346	$639,253	$66,367,095
6	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)							
	6a New approved Docket E-2, Sub 1204 allocation factor	Input Annually	42.78%	5.09%	29.21%	21.90%	1.02%	100.00%
	6b System incurred expense	Input						$93,963,527
	6c NC incurred expense by class	L4f * L6a * L6b	$25,570,495	$3,042,399	$17,459,424	$13,090,085	$609,675	$59,772,079
	6d NC Incurred base fuel rates (¢/kWh)	L6c / L4a * 100	2.06971	2.15197	2.19005	1.93734	2.11442	2.07645
7	Incurred renewable purchased power capacity rates (¢/kWh)							
	7a NC retail production plant %	Input Annually						61.001%
	7b Production plant allocation factors	Input Annually	49.599%	6.156%	28.252%	15.986%	0.007%	100.00%
	7c System incurred expense	Input						$3,670,419
	7d NC incurred renewable capacity expense	L7a* L7b* L7c	$1,110,514	$137,825	$632,549	$357,934	$163	$2,238,985
	7e NC incurred rates by class	L7d / L4a * 100	0.08989	0.09749	0.07934	0.05297	0.00057	0.07778
8	Total incurred rates by class (¢/kWh)	L6h + 7e	2.1596	2.2495	2.2694	1.9903	2.1150	
9	Difference in ¢/kWh (incurred - billed)	L8 - L5a	(0.16640)	(0.24954)	(0.18661)	(0.06369)	(0.10201)	
10	(Over) / under recovery [See footnote]	L9 * L4a / 100	($2,055,811)	($352,792)	($1,487,684)	($430,337)	($29,414)	($4,356,038)
11	Prior period adjustments	Input						
12	Total (over) / under recovery [See footnote]	L10 + L11	($2,055,811)	($352,792)	($1,487,684)	($430,337)	($29,414)	($4,356,038)
13	Total System Incurred Expenses							$97,633,946
14	Less: Jurisdictional allocation adjustment	Input						81,216
15	Total Fuel and Fuel-related Costs per Schedule 2							$97,552,730
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 2019	$ 12,291,799	7,664,663	508,889	1,817,211	2,215,935	85,101	$ 12,291,799
May	27,656,436	10,340,265	603,324	1,474,141	2,816,304	130,603	15,364,637
June	41,484,352	7,081,848	397,399	2,251,604	3,877,285	219,780	13,827,916
July	60,013,014	7,741,904	612,524	4,436,980	5,404,669	332,585	18,528,662
August	77,910,287	7,629,308	406,378	4,042,108	5,473,681	345,798	17,897,273
September	88,271,887	6,009,366	91,425	843,244	3,166,077	251,488	10,361,600
October	94,229,547	6,177,517	(183,357)	(1,250,862)	1,111,002	103,360	5,957,660
November	111,585,817	9,946,288	894,152	3,635,799	2,734,527	145,504	17,356,270
December	112,574,298	(1,556,451)	(127,643)	487,730	2,102,953	81,892	988,481
January 2020	105,124,558	(5,324,375)	(533,274)	(1,879,357)	290,408	(3,142)	(7,449,740)
February	99,789,505	(4,103,653)	(498,540)	(1,410,803)	675,428	2,515	(5,335,053)
March	95,433,467	(2,055,811)	(352,792)	(1,487,684)	(430,337)	(29,414)	(4,356,038)
Total		$ 49,550,869	$ 1,818,485	$ 12,960,111	$ 29,437,932	$ 1,666,070	$ 95,433,467

Notes:

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

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

_/1 Includes prior period adjustments.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2020

Schedule 5

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	$2,420,963	$7,824,994	-	-	-	-	-
Oil	204,995	14,078	$3,465	-	-	-	-
Gas - CC	-	-	4,725,951	$9,361,202	$11,514,782	$15,109,846	-
Gas - CT	-	-	1,856,581	2,804,626	416,159	-	-
Biogas	-	-	-	404,835	-	-	-
Total	$2,625,958	$7,839,072	$6,585,997	$12,165,828	$11,930,941	$15,109,846	-
Average Cost of Fuel Purchased (¢/MBTU)							
Coal	392.25	414.98	-	-	-	-	-
Oil	1,318.64	1,357.57	-	-	-	-	-
Gas - CC	-	-	423.17	319.30	406.82	345.22	-
Gas - CT	-	-	332.10	318.05	447.68	-	-
Biogas	-	-	-	2,697.10	-	-	-
Weighted Average	415.01	415.49	392.79	329.30	408.12	345.22	-
Cost of Fuel Burned ($)							
Coal	$2,306,334	$7,058,391	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	139,059	76,244	$1,792	-	-	-	$4,939
Gas - CC	-	-	4,725,951	$9,361,202	$11,514,782	$15,109,846	-
Gas - CT	-	-	1,856,581	2,804,626	416,159	-	-
Biogas	-	-	-	404,835	-	-	-
Nuclear	-	-	-	-	-	-	-
Total	$2,445,393	$7,134,635	$6,584,324	$12,570,663	$11,930,941	$15,109,846	$4,939
Average Cost of Fuel Burned (¢/MBTU)							
Coal	343.97	345.74	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	1,423.91	1,448.68	1,367.94	-	-	-	1,685.55
Gas - CC	-	-	423.17	319.30	406.82	345.22	-
Gas - CT	-	-	332.10	318.05	447.68	-	-
Biogas	-	-	-	2,697.10	-	-	-
Nuclear	-	-	-	-	-	-	-
Weighted Average	359.48	348.58	392.87	328.34	408.12	345.22	1,685.55
Average Cost of Generation (¢/kWh)							
Coal	4.08	4.00	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	16.88	16.43	16.57	-	-	-	-
Gas - CC	-	-	2.92	2.85	2.90	2.52	-
Gas - CT	-	-	4.03	1.95	4.28	-	-
Biogas	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-
Weighted Average	4.26	4.03	3.17	2.66	2.94	2.52	-
Burned MBTU's							
Coal	670,496	2,041,525	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	9,766	5,263	131	-	-	-	293
Gas - CC	-	-	1,116,797	2,931,744	2,830,444	4,376,842	-
Gas - CT	-	-	559,045	881,811	92,958	-	-
Biogas	-	-	-	15,010	-	-	-
Nuclear	-	-	-	-	-	-	-
Total	680,262	2,046,788	1,675,973	3,828,565	2,923,402	4,376,842	293
Net Generation (mWh)							
Coal	56,570	176,447	-	-	-	-	-
Oil - CC	-	-	-	-	-	-	-
Oil - Steam/CT	824	464	11	-	-	-	(88)
Gas - CC	-	-	161,897	328,030	396,470	599,973	-
Gas - CT	-	-	46,053	143,798	9,719	-	-
Biogas	-	-	-	1,544	-	-	-
Nuclear	-	-	-	-	-	-	-
Hydro (Total System)							
Solar (Total System)							
Total	57,394	176,911	207,961	473,372	406,189	599,973	(88)
Cost of Reagents Consumed ($)							
Ammonia	$9,305	$45,466	-	$21,317	-	-	-
Limestone	93,028	194,463	-	-	-	-	-
Re-emission Chemical	-	-	-	-	-	-	-
Sorbents	62,552	85,511	-	-	-	-	-
Urea	-	-	-	-	-	-	-
Total	$164,885	$325,440	-	$21,317	-	-	-

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.
Asheville Steam was retired effective January 29, 2020.
Re-emission chemical reagent expense is not recoverable in NC.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2020

Schedule 5

Description	Darlington CT	Wayne County CT	Weatherspoon CT	Brunswick Nuclear	Harris Nuclear	Robinson Nuclear	Current Month	Total 12 ME March 2020
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	-	-	$10,245,957	$346,278,799
Oil	-	-	-	$42	$12,658	-	235,238	12,051,112
Gas - CC	-	-	-	-	-	-	40,711,781	532,121,009
Gas - CT	$10	$28	$24	-	-	-	5,077,428	90,464,471
Biogas	-	-	-	-	-	-	404,835	2,449,337
Total	$10	$28	$24	$42	$12,658	-	$56,675,239	$983,364,728
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	-	-	409.37	343.77
Oil	-	-	-	-	1,223.00	-	1,335.21	1,482.46
Gas - CC	-	-	-	-	-	-	361.70	375.66
Gas - CT	333.33	17.95	-	-	-	-	331.00	364.34
Biogas	-	-	-	-	-	-	2,697.10	2,817.08
Weighted Average	333.33	17.95	-	-	1,223.00	-	370.09	366.82
Cost of Fuel Burned ($)								
Coal	-	-	-	-	-	-	$9,364,725	$311,732,857
Oil - CC	-	-	-	-	-	-	-	525,645
Oil - Steam/CT	-	-	$17,054	-	-	-	239,088	10,305,123
Gas - CC	-	-	-	-	-	-	40,711,781	532,121,009
Gas - CT	$10	$28	24	-	-	-	5,077,428	90,464,471
Biogas	-	-	-	-	-	-	404,835	2,449,337
Nuclear	-	-	-	$4,451,280	$3,888,768	$3,303,190	11,643,238	175,626,195
Total	$10	$28	$17,078	$4,451,280	$3,888,768	$3,303,190	$67,441,094	$1,123,224,637
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	-	-	345.30	342.62
Oil - CC	-	-	-	-	-	-	-	1,568.39
Oil - Steam/CT	-	-	1,590.86	-	-	-	1,446.82	1,436.22
Gas - CC	-	-	-	-	-	-	361.70	375.66
Gas - CT	333.33	17.95	-	-	-	-	331.00	364.34
Biogas	-	-	-	-	-	-	2,697.10	2,817.08
Nuclear	-	-	-	55.89	56.40	55.67	56.00	58.34
Weighted Average	333.33	17.95	1,593.10	55.89	56.40	55.67	185.65	200.80
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	-	-	4.02	3.72
Oil - CC	-	-	-	-	-	-	-	15.77
Oil - Steam/CT	-	-	-	-	-	-	24.25	18.49
Gas - CC	-	-	-	-	-	-	2.74	2.74
Gas - CT	-	-	-	-	-	-	2.56	3.85
Biogas	-	-	-	-	-	-	26.22	20.36
Nuclear	-	-	-	0.60	0.57	0.56	0.58	0.61
Weighted Average	-	-	-	0.60	0.57	0.56	1.68	1.87
Burned MBTU's								
Coal	-	-	-	-	-	-	2,712,021	90,985,978
Oil - CC	-	-	-	-	-	-	-	33,515
Oil - Steam/CT	-	-	1,072	-	-	-	16,525	717,518
Gas - CC	-	-	-	-	-	-	11,255,827	141,650,895
Gas - CT	3	156	-	-	-	-	1,533,973	24,829,552
Biogas	-	-	-	-	-	-	15,010	86,946
Nuclear	-	-	-	7,964,872	6,894,876	5,933,271	20,793,019	301,060,528
Total	3	156	1,072	7,964,872	6,894,876	5,933,271	36,326,375	559,364,932
Net Generation (mWh)								
Coal	-	-	-	-	-	-	233,017	8,371,720
Oil - CC	-	-	-	-	-	-	-	3,334
Oil - Steam/CT	(201)	-	(24)	-	-	-	986	55,733
Gas - CC	-	-	-	-	-	-	1,486,370	19,405,345
Gas - CT	(237)	(635)	-	-	-	-	198,698	2,350,810
Biogas	-	-	-	-	-	-	1,544	12,032
Nuclear	-	-	-	744,316	677,007	585,375	2,006,698	28,861,332
Hydro (Total System)							73,324	662,207
Solar (Total System)							19,038	258,435
Total	(438)	(635)	(24)	744,316	677,007	585,375	4,019,675	59,980,947
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	-	-	$76,088	$1,980,709
Limestone	-	-	-	-	-	-	287,491	9,805,521
Re-emission Chemical	-	-	-	-	-	-	-	-
Sorbents	-	-	-	-	-	-	148,063	2,979,668
Urea	-	-	-	-	-	-	-	653,016
Total	-	-	-	-	-	-	$511,642	$15,418,914

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2020

Schedule 6

Description	Mayo	Roxboro	Asheville	Smith Energy Complex	Sutton	Lee	Blewett
Coal Data:							
Beginning balance	575,815	1,186,269	-	-	-	-	-
Tons received during period	25,898	76,231	-	-	-	-	-
Inventory adjustments	-	-	-	-	-	-	-
Tons burned during period	27,394	80,375	-	-	-	-	-
Ending balance	574,319	1,182,125	-	-	-	-	-
MBTUs per ton burned	24.48	25.40	-	-	-	-	-
Cost of ending inventory ($/ton)	84.19	87.70	-	-	-	-	-
Oil Data:							
Beginning balance	259,555	424,889	4,567,776	8,007,162	2,608,517	-	758,372
Gallons received during period	112,649	7,516	-	-	-	-	-
Miscellaneous use and adjustments	(388)	(7,516)	-	-	-	-	-
Gallons burned during period	70,951	38,094	856	-	-	-	2,087
Ending balance	300,865	386,795	4,566,920	8,007,162	2,608,517	-	756,285
Cost of ending inventory ($/gal)	1.96	2.00	2.09	2.33	2.80	-	2.37
Natural Gas Data:							
Beginning balance	-	-	-	-	-	-	-
MCF received during period	-	-	1,623,167	3,681,099	2,823,091	4,226,526	-
MCF burned during period	-	-	1,623,167	3,681,099	2,823,091	4,226,526	-
Ending balance	-	-	-	-	-	-	-
Biogas Data:							
Beginning balance	-	-	-	-	-	-	-
MCF received during period	-	-	-	14,493	-	-	-
MCF burned during period	-	-	-	14,493	-	-	-
Ending balance	-	-	-	-	-	-	-
Limestone/Lime Data:							
Beginning balance	13,075	123,479	5,379	-	-	-	-
Tons received during period	-	191	23	-	-	-	-
Inventory adjustments	-	-	-	-	-	-	-
Tons consumed during period	1,609	4,483	-	-	-	-	-
Ending balance	11,466	119,187	5,402	-	-	-	-
Cost of ending inventory ($/ton)	58.08	39.66	67.63	-	-	-	-

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit, terminal and tolling agreement activity.
Gas is burned as received; therefore, inventory balances are not maintained.
The oil inventory data for Wayne reflects the common usage of the oil tank used for both Wayne and Lee units.
Asheville Steam was retired effective January 29, 2020.

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2020

Schedule 6

Description	Darlington	Wayne County	Weatherspoon	Brunswick	Harris	Robinson	Current Month	Total 12 ME March 2020
Coal Data:								
Beginning balance	-	-	-	-	-	-	1,762,084	1,369,435
Tons received during period	-	-	-	-	-	-	102,129	3,993,739
Inventory adjustments	-	-	-	-	-	-	-	63,924
Tons burned during period	-	-	-	-	-	-	107,769	3,631,494
Ending balance	-	-	-	-	-	-	1,756,444	1,756,444
MBTUs per ton burned	-	-	-	-	-	-	25.17	25.05
Cost of ending inventory ($/ton)	-	-	-	-	-	-	86.32	86.32
Oil Data:								
Beginning balance	10,082,557	11,323,612	601,018	161,668	289,531	78,040	39,162,697	38,635,967
Gallons received during period	-	-	-	-	7,499	-	127,664	5,890,663
Miscellaneous use and adjustments	-	-	-	-	-	-	(7,904)	(172,779)
Gallons burned during period	-	-	7,660	3,800	-	-	123,448	5,194,842
Ending balance	10,082,557	11,323,612	593,358	157,868	297,030	78,040	39,159,009	39,159,009
Cost of ending inventory ($/gal)	2.39	2.40	2.23	2.32	2.32	2.32	2.36	2.36
Natural Gas Data:								
Beginning balance	-	-	-	-	-	-	-	-
MCF received during period	3	151	-	-	-	-	12,354,037	161,208,866
MCF burned during period	3	151	-	-	-	-	12,354,037	161,208,866
Ending balance	-	-	-	-	-	-	-	-
Biogas Data:								
Beginning balance	-	-	-	-	-	-	-	-
MCF received during period	-	-	-	-	-	-	14,493	84,148
MCF burned during period	-	-	-	-	-	-	14,493	84,148
Ending balance	-	-	-	-	-	-	-	-
Limestone/Lime Data:								
Beginning balance	-	-	-	-	-	-	141,933	84,576
Tons received during period	-	-	-	-	-	-	214	258,882
Inventory adjustments	-	-	-	-	-	-	-	12,499
Tons consumed during period	-	-	-	-	-	-	6,092	219,902
Ending balance	-	-	-	-	-	-	136,055	136,055
Cost of ending inventory ($/ton)	-	-	-	-	-	-	42.32	42.32

Schedule 7

DUKE ENERGY PROGRESS

ANALYSIS OF COAL PURCHASED

MARCH 2020

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
MAYO	SPOT	12,929	792,414	61.29
	CONTRACT	12,969	934,292	72.04
	FIXED TRANSPORTATION/ADJUSTMENTS	-	694,257	-
	TOTAL	25,898	2,420,963	93.48
ROXBORO	SPOT	25,684	1,746,247	67.99
	CONTRACT	50,547	3,462,512	68.50
	FIXED TRANSPORTATION/ADJUSTMENTS	-	2,616,235	-
	TOTAL	76,231	7,824,994	102.65
ALL PLANTS	SPOT	38,613	2,538,661	65.75
	CONTRACT	63,516	4,396,804	69.22
	FIXED TRANSPORTATION/ADJUSTMENTS	-	3,310,492	-
	TOTAL	102,129	$ 10,245,957	$ 100.32

Note: Asheville Steam was retired effective January 29, 2020.

Schedule 8

DUKE ENERGY PROGRESS

ANALYSIS OF COAL QUALITY RECEIVED

MARCH 2020

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
MAYO	7.68	12.59	11,916	0.72
ROXBORO	7.13	10.10	12,368	1.51

Schedule 9

DUKE ENERGY PROGRESS
ANALYSIS OF OIL PURCHASED
MARCH 2020

	HARRIS	MAYO	ROXBORO
VENDOR	Hightowers Petroleum Co.	Greensboro Tank Farm	Greensboro Tank Farm
SPOT/CONTRACT	Contract	Contract	Contract
SULFUR CONTENT %	0	0	0
GALLONS RECEIVED	7,499	112,649	7,516
TOTAL DELIVERED COST	$ 12,658	$ 204,995	$ 14,078
DELIVERED COST/GALLON	$ 1.69	$ 1.82	$ 1.87
BTU/GALLON	138,000	138,000	138,000

Notes: Sampling charges of $3,465 for the Asheville station as well as a price adjustment of $42 at the Brunswick station are excluded.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2019 - March, 2020
Nuclear Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Brunswick 1	7,128,000	938	86.51	86.63
Brunswick 2	7,769,042	932	94.90	95.08
Harris 1	7,573,813	964	89.44	88.78
Robinson 2	6,390,477	746	97.59	93.36

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2019 through March, 2020
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Lee Energy Complex	1A	1,335,397	225	67.57	79.83
Lee Energy Complex	1B	1,324,225	227	66.41	79.42
Lee Energy Complex	1C	1,327,528	228	66.29	78.35
Lee Energy Complex	ST1	2,583,040	379	77.59	85.96
Lee Energy Complex	Block Total	6,570,190	1,059	70.63	81.62
Richmond County CC	7	1,238,043	194	72.65	84.85
Richmond County CC	8	1,207,755	194	70.87	83.83
Richmond County CC	ST4	1,402,448	182	87.72	92.23
Richmond County CC	9	1,111,924	216	58.60	67.03
Richmond County CC	10	1,126,860	216	59.39	67.38
Richmond County CC	ST5	1,517,693	248	69.67	72.67
Richmond County CC	Block Total	7,604,723	1,250	69.26	77.25
Sutton Energy Complex	1A	1,369,913	224	69.62	81.09
Sutton Energy Complex	1B	1,363,885	224	69.32	78.83
Sutton Energy Complex	ST1	1,669,503	271	70.13	86.87
Sutton Energy Complex	Block Total	4,403,301	719	69.72	82.57
Asheville CC	ACC CT5	442,184	122	41.29	95.33
Asheville CC	ACC CT7	212,473	109	22.35	97.81
Asheville CC	ACC ST6	188,230	47	45.83	91.08
Asheville CC	Block Total	842,887	278	34.65	95.54

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, 2019 through March, 2020

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Mayo 1	1,309,878	746	19.99	78.39
Roxboro 2	1,338,613	673	22.64	72.78
Roxboro 3	2,360,440	698	38.50	78.81
Roxboro 4	2,074,949	711	33.22	75.61

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, 2019 through March, 2020
Other Cycling Steam Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Asheville	1	521,985	192	37.30	95.85
Asheville	2	252,671	192	18.05	93.30
Roxboro	1	555,880	380	16.65	64.18

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, 2019 through March, 2020
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Asheville CT	382,417	364	91.89
Blewett CT	-689	68	96.98
Darlington CT	20,462	767	91.00
Richmond County CT	1,620,095	934	88.42
Sutton Fast Start CT	211,140	98	90.80
Wayne County CT	130,617	963	94.81
Weatherspoon CT	-196	164	80.15

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, 2019 through March, 2020
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Blewett	-421	27.0	0.00
Marshall	-271	4.0	5.26
Tillery	214,200	84.0	84.85
Walters	448,699	113.0	68.08

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, 2019 through March, 2020
Pre-commercial Combined Cycle Units

Note: The Power Plant Performance Data reports are limited to capturing data beginning the first full month a station is in commercial operation. During the months specified below, Asheville CC produced pre-commercial generation.

Production Month	Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
November 2019	Asheville	ST8	97	n/a	n/a	n/a
December 2019	Asheville	ST8	-	n/a	n/a	n/a
January 2020	Asheville	ST8	-	n/a	n/a	n/a
February 2020	Asheville	ST8	-	n/a	n/a	n/a
March 2020	Asheville	ST8	(487)	n/a	n/a	n/a

Notes:

Asheville CT5 and ST6 were placed in service during December 2019, and Asheville CT7 was placed in service during January 2020; pre-commercial generation for those units is presented on the Twelve Month Summary for Combined Cycle Units.

Duke Energy Progress
Base Load Power Plant Performance Review Plan

Period: March, 2020

Station	Unit	Date of Outage	Duration of Outage	Scheduled / Unscheduled	Cause of Outage	Reason Outage Occurred	Remedial Action Taken
Brunswick	1	02/29/2020 - 03/25/2020	575.75	Scheduled	B1R23 refueling outage	Refueling outage.	None
	1	03/25/2020 - 03/28/2020	72.02	Unscheduled	B1R23 refueling outage - outage extension due to safety relief valve leak	Safety relief valve leak.	The valve leak was repaired.
	2	None					
Harris	1	03/23/2020 - 03/25/2020	51.52	Unscheduled	Unit trip from full power on hydraulic control header pressure loss	Solenoid valve was opened causing a pressure transient that caused a pressure setpoint to be reached, which initiated an automatic reactor trip through the reactor protection system.	Site taking action to review valve online maintenance/replacement procedures to ensure similar situations are executed in a manner that avoids an automatic reactor trip in the future.
Robinson	2	None					

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2020

DEP Asheville CC

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
ACC CT5	3/23/2020 1:36:00 AM To 4/1/2020 12:00:00 AM	Sch	9300	Transmission System Problems Other Than Catastroph	Transmission GMS outage	
ACC ST6	3/23/2020 1:30:00 AM To 4/1/2020 12:00:00 AM	Sch	9300	Transmission System Problems Other Than Catastroph	Planned Transmission GMS Outage	
ACC CT7	3/2/2020 5:33:00 PM To 3/2/2020 7:32:00 PM	Unsch	5190	Other Gas Turbine Auxiliary System Problems	All air compressors tripped by vendor	

Lee Energy Complex

No Outages at Baseload Units During the Month.

Mayo Station

No Outages at Baseload Units During the Month.

Richmond County Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
7	3/5/2020 9:34:00 PM To 3/5/2020 11:08:00 PM	Unsch	3619	Other Switchyard Equipment	Fire in switchyard reactor bank.	
8	3/5/2020 9:34:00 PM To 3/5/2020 11:31:00 PM	Unsch	3619	Other Switchyard Equipment	Fire in switchyard reactor bank.	
ST4	3/5/2020 9:34:00 PM To 3/6/2020 12:39:00 AM	Unsch	3619	Other Switchyard Equipment	Fire in switchyard reactor bank.	
9	2/28/2020 12:04:00 PM To 3/30/2020 8:00:00 PM	Sch	4840	Generator Inspection	Perform robotic inspection, Gen Med.	
10	2/28/2020 10:42:00 AM To 4/5/2020 10:14:00 AM	Sch	4899	Other Miscellaneous Generator Problems	Replace cracked support fixator. Perform Gen Med.	
ST5	2/28/2020 11:20:00 AM To 3/30/2020 8:00:00 PM	Sch	4640	Generator Seal Oil System And Seals	Replace seal oil regulator.	

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 2020

Roxboro Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
2	2/29/2020 12:00:00 AM To 4/1/2020 12:00:00 AM	Sch	1800	Major Boiler Overhaul (720 Hours or Longer)	Planned Outage	
3	3/31/2020 7:00:00 AM To 4/7/2020 4:30:00 PM	Sch	4260	Turbine Main Stop Valves	Turbine Stop Valve Inspection	
4	3/7/2020 12:00:00 AM To 4/1/2020 12:00:00 AM	Sch	1800	Major Boiler Overhaul (720 Hours or Longer)	Planned Outage	

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 2020
Brunswick Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	938		932	
(B) Period Hours	743		743	
(C) Net Gen (mWh) and Capacity Factor (%)	45,281	6.50	699,035	100.95
(D) Net mWh Not Gen due to Full Schedule Outages	540,054	77.49	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	17,651	2.53	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	67,552	9.69	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	26,396	3.79	-6,559	-0.95
* (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 (%)		7.05		99.69
(L) Output Factor (%)		50.69		100.95
(M) Heat Rate (BTU/NkWh)		12,888		10,559

*** Estimate**
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2020
Harris Nuclear Station

	Unit 1	
(A) MDC (mW)	964	
(B) Period Hours	743	
(C) Net Gen (mWh) and Capacity Factor (%)	677,007	94.52
(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	49,662	6.93
* (G) Net mWh Not Gen due to Partial Forced Outages	-10,417	-1.45
* (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 (%)		91.95
(L) Output Factor (%)		101.56
(M) Heat Rate (BTU/NkWh)		10,184

*** Estimate**
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2020
Robinson Nuclear Station

	Unit 2	
(A) MDC (mW)	759	
(B) Period Hours	743	
(C) Net Gen (mWh) and Capacity Factor (%)	585,375	103.80
(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	-21,438	-3.80
* (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 (%)		103.80
(M) Heat Rate (BTU/NkWh)		10,136

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2020
DEP Asheville CC

	ACC CT5	ACC ST6	Block Total
(A) MDC (mW)	190	90	280
(B) Period Hrs	743	743	743
(C) Net Generation (mWh)	89,323	46,132	135,455
(D) Capacity Factor (%)	63.27	68.99	65.11
(E) Net mWh Not Generated due to Full Scheduled Outages	40,736	19,305	60,041
(F) Scheduled Outages: percent of Period Hrs	28.86	28.87	28.86
(G) Net mWh Not Generated due to Partial Scheduled Outages	9,779	1,585	11,365
(H) Scheduled Derates: percent of Period Hrs	6.93	2.37	5.46
(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	1,332	0	1,332
(N) Economic Dispatch: percent of Period Hrs	0.94	0.00	0.64
(O) Net mWh Possible in Period	141,170	66,870	208,040
(P) Equivalent Availability (%)	64.22	68.76	65.68
(Q) Output Factor (%)	88.94	96.99	91.52
(R) Heat Rate (BTU/NkWh)	8,372	0	5,521

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 2020
DEP Asheville CC

	ACC CT7	Block Total
(A) MDC (mW)	190	190
(B) Period Hrs	743	743
(C) Net Generation (mWh)	26,929	26,929
(D) Capacity Factor (%)	19.08	19.08
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	13,709	13,709
(H) Scheduled Derates: percent of Period Hrs	9.71	9.71
(I) Net mWh Not Generated due to Full Forced Outages	377	377
(J) Forced Outages: percent of Period Hrs	0.27	0.27
(K) Net mWh Not Generated due to Partial Forced Outages	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	100,155	100,155
(N) Economic Dispatch: percent of Period Hrs	70.95	70.95
(O) Net mWh Possible in Period	141,170	141,170
(P) Equivalent Availability (%)	90.02	90.02
(Q) Output Factor (%)	72.79	72.79
(R) Heat Rate (BTU/NkWh)	13,678	13,678

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 2020
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)	119,013	117,351	120,225	243,384	599,973
(D) Capacity Factor (%)	71.19	69.58	70.97	86.43	76.25
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	20,433	21,175	21,547	371	63,526
(H) Scheduled Derates: percent of Period Hrs	12.22	12.56	12.72	0.13	8.07
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	27,730	30,135	27,632	37,842	123,338
(N) Economic Dispatch: percent of Period Hrs	16.59	17.87	16.31	13.44	15.68
(O) Net mWh Possible in Period	167,175	168,661	169,404	281,597	786,837
(P) Equivalent Availability (%)	87.78	87.44	87.28	99.87	91.93
(Q) Output Factor (%)	71.19	69.58	70.97	86.43	76.25
(R) Heat Rate (BTU/NkWh)	9,405	9,688	9,529	4,014	7,298

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 2020
Richmond County Station

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	194	194	182	570
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	105,582	101,705	122,737	330,024
(D) Capacity Factor (%)	73.25	70.56	90.76	77.93
(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	14,829	14,821	4,809	34,459
(H) Scheduled Derates: percent of Period Hrs	10.29	10.28	3.56	8.14
(I) Net mWh Not Generated due to Full Forced Outages	304	378	561	1,243
(J) Forced Outages: percent of Period Hrs	0.21	0.26	0.41	0.29
(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	23,427	27,238	7,118	57,783
(N) Economic Dispatch: percent of Period Hrs	16.25	18.90	5.26	13.64
(O) Net mWh Possible in Period	144,142	144,142	135,226	423,510
(P) Equivalent Availability (%)	89.50	89.46	96.03	91.57
(Q) Output Factor (%)	73.48	72.68	91.31	78.94
(R) Heat Rate (BTU/NkWh)	11,139	11,078	0	6,977

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 2020
Richmond County Station

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	216	216	248	680
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	-225	-225	0	-450
(D) Capacity Factor (%)	0.00	0.00	0.00	0.00
(E) Net mWh Not Generated due to Full Scheduled Outages	154,440	160,488	177,320	492,248
(F) Scheduled Outages: percent of Period Hrs	96.23	100.00	96.23	97.43
(G) Net mWh Not Generated due to Partial Scheduled Outages	504	0	0	504
(H) Scheduled Derates: percent of Period Hrs	0.31	0.00	0.00	0.10
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	5,544	0	6,944	12,488
(N) Economic Dispatch: percent of Period Hrs	3.45	0.00	3.77	2.47
(O) Net mWh Possible in Period	160,488	160,488	184,264	505,240
(P) Equivalent Availability (%)	3.45	0.00	3.77	2.47
(Q) Output Factor (%)	0.00	0.00	0.00	0.00
(R) Heat Rate (BTU/NkWh)	0	0	0	0

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 2020
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)	121,465	122,337	152,668	396,470
(D) Capacity Factor (%)	72.98	73.51	75.82	74.22
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	20,061	19,689	1,857	41,608
(H) Scheduled Derates: percent of Period Hrs	12.05	11.83	0.92	7.79
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	24,906	24,406	46,828	96,139
(N) Economic Dispatch: percent of Period Hrs	14.96	14.66	23.26	18.00
(O) Net mWh Possible in Period	166,432	166,432	201,353	534,217
(P) Equivalent Availability (%)	87.95	88.17	99.08	92.21
(Q) Output Factor (%)	72.98	73.51	75.82	74.22
(R) Heat Rate (BTU/NkWh)	11,615	11,615	0	7,143

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
Baseload Power Plant
Performance Review Plan
March 2020

Pre-commercial Generation
Asheville Combined Cycle

		Unit ST8	Block Total
(A)	**MDC (mW)**		
(B)	**Period Hrs**		
(C)	**Net Generation (mWh)**	(487)	(487)
(D)	**Capacity Factor (%)**		
(E)	**Net mWh Not Generated due to Full Scheduled Outages**		
(F)	**Scheduled Outages: percent of Period Hrs**		
(G)	**Net mWh Not Generated due to Partial Scheduled Outages**		
(H)	**Scheduled Derates: percent of Period Hrs**		
(I)	**Net mWh Not Generated due to Full Forced Outages**		
(J)	**Forced Outages: percent of Period Hrs**		
(K)	**Net mWh Not Generated due to Partial Forced Outages**		
(L)	**Forced Derates: percent of Period Hrs**		
(M)	**Net mWh Not Generated due to Economic Dispatch**		
(N)	**Economic Dispatch: percent of Period Hrs**		
(O)	**Net mWh Possible in Period**		
(P)	**Equivalent Availability (%)**		
(Q)	**Output Factor (%)**		
(R)	**Heat Rate (BTU/NkWh)**		

Note: The Power Plant Performance Data reports are limited to capturing data beginning the first full month a station is in commercial operation. During the month specified above, Asheville CC produced pre-commercial generation.

Duke Energy Progress
Intermediate Power Plant Performance
Review Plan
March 2020

		Mayo Station
		Unit 1
(A)	**MDC (mW)**	746
(B)	**Period Hrs**	743
(C)	**Net Generation (mWh)**	57,394
(D)	**Net mWh Possible in Period**	554,278
(E)	**Equivalent Availability (%)**	80.44
(F)	**Output Factor (%)**	37.21
(G)	**Capacity Factor (%)**	10.35

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 2020

Roxboro Station

		Unit 2	Unit 3	Unit 4
(A)	MDC (mW)	673	698	711
(B)	Period Hrs	743	743	743
(C)	Net Generation (mWh)	-941	180,495	-2,238
(D)	Net mWh Possible in Period	500,039	518,614	528,273
(E)	Equivalent Availability (%)	0.00	90.89	19.38
(F)	Output Factor (%)	0.00	37.27	0.00
(G)	Capacity Factor (%)	0.00	34.80	0.00

Notes:

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

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2019 - March 2020
Brunswick Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	938		932	
(B) Period Hours	8784		8784	
(C) Net Gen (mWh) and Capacity Factor (%)	7,128,000	86.51	7,769,042	94.90
(D) Net mWh Not Gen due to Full Schedule Outages	561,863	6.82	45,948	0.56
* (E) Net mWh Not Gen due to Partial Scheduled Outages	34,020	0.41	47,691	0.58
(F) Net mWh Not Gen due to Full Forced Outages	505,879	6.14	276,773	3.38
* (G) Net mWh Not Gen due to Partial Forced Outages	9,630	0.12	47,234	0.58
* (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	8,239,392	100.00%	8,186,688	100.00%
(K) Equivalent Availability (%)		86.63		95.08
(L) Output Factor (%)		99.39		98.79
(M) Heat Rate (BTU/NkWh)		10,499		10,629

*** Estimate**
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2019 - March 2020
Harris Nuclear Station

	Unit 1	
(A) MDC (mW)	964	
(B) Period Hours	8784	
(C) Net Gen (mWh) and Capacity Factor (%)	7,573,813	89.44
(D) Net mWh Not Gen due to Full Schedule Outages	869,962	10.27
* (E) Net mWh Not Gen due to Partial Scheduled Outages	61,610	0.73
(F) Net mWh Not Gen due to Full Forced Outages	49,662	0.59
* (G) Net mWh Not Gen due to Partial Forced Outages	-87,271	-1.03
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	8,467,776	100.00%
(K) Equivalent Availability (%)		88.78
(L) Output Factor (%)		100.34
(M) Heat Rate (BTU/NkWh)		10,305

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2019 - March 2020
Robinson Nuclear Station

	Unit 2	
(A) MDC (mW)	759	
(B) Period Hours	8784	
(C) Net Gen (mWh) and Capacity Factor (%)	6,390,477	97.59
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	7,076	0.11
(F) Net mWh Not Gen due to Full Forced Outages	408,699	6.24
* (G) Net mWh Not Gen due to Partial Forced Outages	-258,014	-3.94
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	6,548,238	100.00%
(K) Equivalent Availability (%)		93.36
(L) Output Factor (%)		104.13
(M) Heat Rate (BTU/NkWh)		10,267

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2019 through March, 2020

DEP Asheville CC

	ACC CT5	ACC ST6	Block Total
(A) MDC (mW)	183	94	276
(B) Period Hrs	5,856	4,392	4,392
(C) Net Generation (mWh)	442,184	188,230	630,414
(D) Capacity Factor (%)	41.29	45.83	42.55
(E) Net mWh Not Generated due to Full Scheduled Outages	41,296	19,305	60,601
(F) Scheduled Outages: percent of Period Hrs	3.86	4.70	4.09
(G) Net mWh Not Generated due to Partial Scheduled Outages	9,779	1,585	11,365
(H) Scheduled Derates: percent of Period Hrs	0.91	0.39	0.77
(I) Net mWh Not Generated due to Full Forced Outages	842	14,365	15,208
(J) Forced Outages: percent of Period Hrs	0.08	3.50	1.03
(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	576,831	187,257	764,088
(N) Economic Dispatch: percent of Period Hrs	53.86	45.59	51.57
(O) Net mWh Possible in Period	1,070,933	410,743	1,481,676
(P) Equivalent Availability (%)	95.33	91.08	94.12
(Q) Output Factor (%)	78.79	96.71	83.40
(R) Heat Rate (BTU/NkWh)	10,009	0	7,021

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, 2019 through March, 2020

DEP Asheville CC

	ACC CT7	Block Total
(A) MDC (mW)	186	186
(B) Period Hrs	5,112	5,112
(C) Net Generation (mWh)	212,473	212,473
(D) Capacity Factor (%)	22.35	22.35
(E) Net mWh Not Generated due to Full Scheduled Outages	4,342	4,342
(F) Scheduled Outages: percent of Period Hrs	0.46	0.46
(G) Net mWh Not Generated due to Partial Scheduled Outages	13,709	13,709
(H) Scheduled Derates: percent of Period Hrs	1.44	1.44
(I) Net mWh Not Generated due to Full Forced Outages	3,173	3,173
(J) Forced Outages: percent of Period Hrs	0.33	0.33
(K) Net mWh Not Generated due to Partial Forced Outages	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	717,081	717,081
(N) Economic Dispatch: percent of Period Hrs	75.42	75.42
(O) Net mWh Possible in Period	950,777	950,777
(P) Equivalent Availability (%)	97.81	97.81
(Q) Output Factor (%)	62.14	62.14
(R) Heat Rate (BTU/NkWh)	10,213	10,213

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, 2019 through March, 2020

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	8,784	8,784	8,784	8,784	8,784
(C) Net Generation (mWh)	1,335,397	1,324,225	1,327,528	2,583,040	6,570,190
(D) Capacity Factor (%)	67.57	66.41	66.29	77.59	70.63
(E) Net mWh Not Generated due to Full Scheduled Outages	140,610	146,124	166,296	434,675	887,704
(F) Scheduled Outages: percent of Period Hrs	7.11	7.33	8.30	13.06	9.54
(G) Net mWh Not Generated due to Partial Scheduled Outages	254,159	258,949	262,876	23,687	799,671
(H) Scheduled Derates: percent of Period Hrs	12.86	12.99	13.13	0.71	8.60
(I) Net mWh Not Generated due to Full Forced Outages	3,791	5,195	4,340	8,471	21,796
(J) Forced Outages: percent of Period Hrs	0.19	0.26	0.22	0.25	0.23
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	732	732
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.02	0.01
(M) Net mWh Not Generated due to Economic Dispatch	242,442	259,476	241,713	278,531	1,022,162
(N) Economic Dispatch: percent of Period Hrs	12.27	13.01	12.07	8.37	10.99
(O) Net mWh Possible in Period	1,976,400	1,993,968	2,002,752	3,329,136	9,302,256
(P) Equivalent Availability (%)	79.83	79.42	78.35	85.96	81.62
(Q) Output Factor (%)	74.70	73.57	73.91	89.57	79.47
(R) Heat Rate (BTU/NkWh)	9,208	9,404	9,370	4,439	7,406

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, 2019 through March, 2020

Richmond County Station

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	194	194	182	570
(B) Period Hrs	8,784	8,784	8,784	8,784
(C) Net Generation (mWh)	1,238,043	1,207,755	1,402,448	3,848,246
(D) Capacity Factor (%)	72.65	70.87	87.72	76.86
(E) Net mWh Not Generated due to Full Scheduled Outages	51,943	37,875	21,506	111,325
(F) Scheduled Outages: percent of Period Hrs	3.05	2.22	1.35	2.22
(G) Net mWh Not Generated due to Partial Scheduled Outages	199,018	206,053	91,016	496,087
(H) Scheduled Derates: percent of Period Hrs	11.68	12.09	5.69	9.91
(I) Net mWh Not Generated due to Full Forced Outages	7,139	31,658	5,129	43,926
(J) Forced Outages: percent of Period Hrs	0.42	1.86	0.32	0.88
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	6,515	6,515
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.41	0.13
(M) Net mWh Not Generated due to Economic Dispatch	207,953	220,755	72,073	500,781
(N) Economic Dispatch: percent of Period Hrs	12.20	12.95	4.51	10.00
(O) Net mWh Possible in Period	1,704,096	1,704,096	1,598,688	5,006,880
(P) Equivalent Availability (%)	84.85	83.83	92.23	86.86
(Q) Output Factor (%)	77.22	77.14	91.55	81.87
(R) Heat Rate (BTU/NkWh)	11,610	11,292	0	7,279

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, 2019 through March, 2020

Richmond County Station

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	216	216	248	680
(B) Period Hrs	8,784	8,784	8,784	8,784
(C) Net Generation (mWh)	1,111,924	1,126,860	1,517,693	3,756,477
(D) Capacity Factor (%)	58.60	59.39	69.67	62.89
(E) Net mWh Not Generated due to Full Scheduled Outages	462,503	460,206	556,247	1,478,956
(F) Scheduled Outages: percent of Period Hrs	24.38	24.26	25.53	24.76
(G) Net mWh Not Generated due to Partial Scheduled Outages	162,892	157,746	13,060	333,699
(H) Scheduled Derates: percent of Period Hrs	8.59	8.31	0.60	5.59
(I) Net mWh Not Generated due to Full Forced Outages	112	1,001	26,135	27,247
(J) Forced Outages: percent of Period Hrs	0.01	0.05	1.20	0.46
(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	159,669	151,287	65,296	376,253
(N) Economic Dispatch: percent of Period Hrs	8.42	7.97	3.00	6.30
(O) Net mWh Possible in Period	1,897,344	1,897,344	2,178,432	5,973,120
(P) Equivalent Availability (%)	67.03	67.38	72.67	69.20
(Q) Output Factor (%)	82.05	81.70	96.75	87.30
(R) Heat Rate (BTU/NkWh)	11,470	11,463	0	6,834

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, 2019 through March, 2020

Sutton Energy Complex

	Unit 1A	Unit 1B	Unit ST1	Block Total
(A) MDC (mW)	224	224	271	719
(B) Period Hrs	8,784	8,784	8,784	8,784
(C) Net Generation (mWh)	1,369,913	1,363,885	1,669,503	4,403,301
(D) Capacity Factor (%)	69.62	69.32	70.13	69.72
(E) Net mWh Not Generated due to Full Scheduled Outages	105,321	127,799	197,500	430,621
(F) Scheduled Outages: percent of Period Hrs	5.35	6.50	8.30	6.82
(G) Net mWh Not Generated due to Partial Scheduled Outages	263,839	254,211	84,286	602,336
(H) Scheduled Derates: percent of Period Hrs	13.41	12.92	3.54	9.54
(I) Net mWh Not Generated due to Full Forced Outages	2,923	34,474	0	37,397
(J) Forced Outages: percent of Period Hrs	0.15	1.75	0.00	0.59
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	30,675	30,675
(L) Forced Derates: percent of Period Hrs	0.00	0.00	1.29	0.49
(M) Net mWh Not Generated due to Economic Dispatch	225,620	187,247	398,500	811,367
(N) Economic Dispatch: percent of Period Hrs	11.47	9.52	16.74	12.85
(O) Net mWh Possible in Period	1,967,616	1,967,616	2,380,464	6,315,696
(P) Equivalent Availability (%)	81.09	78.83	86.87	82.57
(Q) Output Factor (%)	75.93	76.35	76.81	76.39
(R) Heat Rate (BTU/NkWh)	11,604	11,594	0	7,201

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
Baseload Power Plant
Performance Review Plan
April, 2019 through March, 2020

Pre-commercial Generation
Asheville Combined Cycle

		Unit ST8	Block Total
(A)	**MDC (mW)**		
(B)	**Period Hrs**		
(C)	**Net Generation (mWh)**	(390)	(390)
(D)	**Capacity Factor (%)**		
(E)	**Net mWh Not Generated due to Full Scheduled Outages**		
(F)	**Scheduled Outages: percent of Period Hrs**		
(G)	**Net mWh Not Generated due to Partial Scheduled Outages**		
(H)	**Scheduled Derates: percent of Period Hrs**		
(I)	**Net mWh Not Generated due to Full Forced Outages**		
(J)	**Forced Outages: percent of Period Hrs**		
(K)	**Net mWh Not Generated due to Partial Forced Outages**		
(L)	**Forced Derates: percent of Period Hrs**		
(M)	**Net mWh Not Generated due to Economic Dispatch**		
(N)	**Economic Dispatch: percent of Period Hrs**		
(O)	**Net mWh Possible in Period**		
(P)	**Equivalent Availability (%)**		
(Q)	**Output Factor (%)**		
(R)	**Heat Rate (BTU/NkWh)**		

Note: The Power Plant Performance Data reports are limited to capturing data beginning the first full month a station is in commercial operation. During the months specified above, Asheville CC produced pre-commercial generation.

Duke Energy Progress
Intermediate Power Plant
Performance Review Plan
April, 2019 through March, 2020

Mayo Station

Units	Unit 1
(A) MDC (mW)	746
(B) Period Hrs	8,784
(C) Net Generation (mWh)	1,309,878
(D) Net mWh Possible in Period	6,552,864
(E) Equivalent Availability (%)	78.39
(F) Output Factor (%)	44.14
(G) Capacity Factor (%)	19.99

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, 2019 through March, 2020

Roxboro Station

Units	Unit 2	Unit 3	Unit 4
(A) MDC (mW)	673	698	711
(B) Period Hrs	8,784	8,784	8,784
(C) Net Generation (mWh)	1,338,613	2,360,440	2,074,949
(D) Net mWh Possible in Period	5,911,632	6,131,232	6,245,424
(E) Equivalent Availability (%)	72.78	78.81	75.61
(F) Output Factor (%)	61.38	55.52	65.21
(G) Capacity Factor (%)	22.64	38.50	33.22

Notes:

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

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 1**

North Carolina Annual Fuel and Fuel Related Expense

Proposed Nuclear Capacity Factor

Billing Period December 1, 2020 - November 30, 2021

Docket No. E-2, Sub 1250

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs	8,052,542	7,453,018	7,708,915	6,515,863	29,730,338
Hours in Year	8,760	8,160	8,160	8,760	8,760
MDC	938	932	964	759	3,593
Cost	$ 50,373,402	$ 47,366,985	$ 47,120,590	$ 39,582,952	$ 184,443,928
$/MWhs	$ 6.26	$ 6.36	$ 6.11	$ 6.07	
Avg. $/MWhs					**$ 6.2039**
Cents per kWh					**0.6204**

	GWhs	Capacity Rating MDC	Hours	Proposed Nuclear Capacity Factor
Brunswick 1	8,053	938	8,760	98.00%
Brunswick 2	7,453	932	8,160	98.00%
Harris 1	7,709	964	8,160	98.00%
Robinson 1	6,516	759	8,760	98.00%
	29,730	3,593	8,760	**94.46%**

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, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs with NERC applied	7,759,200	7,181,515	7,244,807	5,938,079	28,123,601
Hours in Year	8,760	8,160	8,160	8,760	8,760
MDC	938	932	964	759	3,593
Capacity Factor-NERC 5yr Avg	0.9443	0.9443	0.9210	0.8931	
Cost ($)	$ 48,137,269	$ 44,553,371	$ 44,946,030	$ 36,839,225	$ 174,475,894
$/MWhs	$ 6.20	$ 6.20	$ 6.20	$ 6.20	
Avg. $/MWHs					**$ 6.20**
Cents per kWh					**0.6204**

	Capacity Rating MDC	NCF Rating	Weighted Average
Brunswick 1	938	94.43%	24.65%
Brunswick 2	932	94.43%	24.49%
Harris 1	964	92.10%	24.71%
Robinson 1	759	89.31%	18.87%
	3,593		**92.72%**

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, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Resource Type		**MWh Dec'20-Nov'21**
Nuclear		29,388,347
Adjust for Higher Nuclear Capacity Factor		341,992
Adjusted Nuclear Total		29,730,338
Coal		8,282,666
Adjust for Higher Nuclear Capacity Factor		(341,992)
Adjusted Coal Total		7,940,674
Gas CT and CC Total		18,943,545
Total Hydro		650,353
Utility Owned Solar Generation		256,176
Total Net Generation		57,521,087
Purchases for REPS Compliance	2,328,214	
Purchases from Qualifying Facilities	4,131,985	
Purchases from Dispatchable Units	1,668,028	
Emergency & DSM Purchases	23,807	
Allocated Economic Purchases	238,305	
Joint Dispatch Fuel Transfer Purchases	1,527,867	9,918,206
Total Net Generation and Purchases		67,439,293
Sales Totals (intersystem sales)	(120,919)	
Fuel Transfer Sales (JDA & economic sales)	(3,927,743)	(4,048,662)
Line Losses and Company Use		(1,906,330)
Total NC System Sales		**61,484,301**

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, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Resource Type			Costs $ Dec'20-Nov'21
Nuclear		$	182,308,964
Adjust for Higher Nuclear Capacity Factor			2,134,964
Adjusted Nuclear			184,443,928
Coal			253,383,902
Adjust for Higher Nuclear Capacity Factor			(10,462,237)
Adjusted Coal Total			242,921,665
Reagent and By-Product Costs			20,467,213
Gas CT and CC Total			490,311,290
Total Hydro			-
Utility Owned Solar Generation			-
Total Generation Costs			938,144,096
Purchases for REPS Compliance	$ 131,543,318		
Purchases for REPS Compliance Capacity	26,962,441		
Purchases from Qualifying Facilities Energy	191,949,817		
Purchases from Qualifying Facilities Capacity	39,344,300		
Purchases from Dispatchable Units	43,444,341		
Emergency & DSM Purchases	1,321,830		
Allocated Economic Purchases	6,460,492		
Joint Dispatch Fuel Transfer Purchases	23,513,124		
Joint Dispatch Savings	(6,373,541)	$	458,166,122
Total Net Generation and Purchases			1,396,310,218
Sales Totals (intersystem sales)	$ (3,019,742)		
Fuel Transfer Sales (JDA & economic sales)	(79,730,585)		(82,750,327)
Total System Fuel and Related Expenses		**$**	**1,313,559,891**

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, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

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	2020	$ 349,864	$ 814,335	$ (10,778)	$ 362,270	$ 180,399	$ 1,696,089	$ (137,395)	$ (9,473)	$ 1,549,221
January	2021	530,045	1,243,582	(58,470)	531,324	271,310	2,517,790	(184,985)	(34,250)	2,298,556
February	2021	486,647	1,106,364	(18,442)	484,868	248,097	2,307,533	8,237,244	(31,693)	10,513,085
March	2021	225,462	533,786	(15,143)	271,583	112,582	1,128,270	(78,870)	(15,924)	1,033,476
April	2021	50,715	117,977	(4,266)	73,946	24,453	262,825	(22,709)	(6,260)	233,857
May	2021	40,061	115,602	(3,723)	55,533	21,867	229,340	(13,722)	(4,933)	210,685
June	2021	131,603	348,989	(7,158)	166,761	72,573	712,769	(42,483)	(10,334)	659,951
July	2021	299,623	776,057	(6,315)	342,645	162,584	1,574,594	(100,921)	(20,696)	1,452,978
August	2021	283,588	773,994	(11,476)	328,284	153,998	1,528,389	(99,490)	(19,355)	1,409,543
September	2021	130,049	360,338	(9,509)	176,383	67,194	724,455	(49,366)	(10,631)	664,458
October	2021	26,849	86,556	-	35,197	14,523	163,125	(8,631)	(4,178)	150,316
November	2021	51,205	165,532	(2,666)	69,982	29,089	313,142	(16,744)	(5,309)	291,090
12ME Nov	2021	$ 2,605,708	$ 6,443,112	$ (147,945)	$ 2,898,776	$ 1,358,671	$ 13,158,322	$ 7,481,928	$ (173,037)	$ 20,467,213

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Fuel Impacts
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

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	2020	$ 257,862	$ 370,766	$ (89,681)	$ (166,045)	$ 4,118,328	$ (4,118,328)	$ 1,146,573	$ (1,146,573)
January	2021	1,176,285	1,661,806	(1,591,816)	(2,350,168)	(2,389,493)	2,389,493	(234,351)	234,351
February	2021	380,540	558,194	(720,710)	(862,253)	(1,617,525)	1,617,525	(12,984)	12,984
March	2021	219,150	325,045	(272,340)	(535,713)	1,780,167	(1,780,167)	1,032,313	(1,032,313)
April	2021	541,903	816,862	(57,018)	(8,586)	(4,758,982)	4,758,982	(754,326)	754,326
May	2021	352,445	508,572	(178,053)	(99,829)	(1,436,148)	1,436,148	286,212	(286,212)
June	2021	442,608	604,720	(115,855)	(139,218)	(5,809,342)	5,809,342	(609,887)	609,887
July	2021	674,261	936,992	(273,546)	(232,353)	(7,206,634)	7,206,634	(1,780,127)	1,780,127
August	2021	596,490	859,410	(148,886)	(80,333)	(7,653,022)	7,653,022	(906,517)	906,517
September	2021	828,916	1,219,925	(129,011)	(84,868)	(6,213,974)	6,213,974	(824,741)	824,741
October	2021	644,344	943,717	(15,058)	(10,720)	(8,113,755)	8,113,755	(1,591,215)	1,591,215
November	2021	345,687	513,412	(101,916)	(91,624)	(13,223,193)	13,223,193	(2,124,492)	2,124,492
Total		$ 6,460,492		$ (3,693,889)		$ (52,523,572)		$ (6,373,541)	

Note: Totals may not sum due to rounding

		Fuel Transfer Payments	
		Purchases	**Sales**
December	2020	$ 6,112,000	$ 1,993,672
January	2021	2,576,329	4,965,823
February	2021	2,356,836	3,974,361
March	2021	3,988,416	2,208,250
April	2021	1,814,652	6,573,634
May	2021	2,577,595	4,013,743
June	2021	1,250,590	7,059,932
July	2021	919,940	8,126,574
August	2021	530,502	8,183,524
September	2021	574,090	6,788,064
October	2021	728,496	8,842,251
November	2021	83,677	13,306,869
		$ 23,513,124	$ 76,036,696
			$ (52,523,572)

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Payments
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

		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	2020	95,054	376,196	(4,644)	4,644	95,054	380,839	$ 20.97	$ 16.05	$ 6,112,000	$ 1,993,672	$ 4,118,328	$ -
January	2021	233,291	114,318	(15,219)	15,219	233,291	129,537	$ 21.29	$ 19.89	2,576,329	4,965,823	-	2,389,493
February	2021	190,075	109,221	(11,642)	11,642	190,075	120,862	$ 20.91	$ 19.50	2,356,836	3,974,361	-	1,617,525
March	2021	115,013	311,791	(6,253)	6,253	115,013	318,043	$ 19.20	$ 12.54	3,988,416	2,208,250	1,780,167	-
April	2021	337,867	92,434	(10,502)	10,502	337,867	102,936	$ 19.46	$ 17.63	1,814,652	6,573,634	-	4,758,982
May	2021	212,748	173,588	(11,559)	11,559	212,748	185,147	$ 18.87	$ 13.92	2,577,595	4,013,743	-	1,436,148
June	2021	352,999	82,716	(4,811)	4,811	352,999	87,527	$ 20.00	$ 14.29	1,250,590	7,059,932	-	5,809,342
July	2021	372,513	63,634	5,245	(5,245)	377,758	63,634	$ 21.51	$ 14.46	919,940	8,126,574	-	7,206,634
August	2021	375,537	38,155	9,330	(9,330)	384,867	38,155	$ 21.26	$ 13.90	530,502	8,183,524	-	7,653,022
September	2021	336,840	39,950	(1,457)	1,457	336,840	41,407	$ 20.15	$ 13.86	574,090	6,788,064	-	6,213,974
October	2021	464,656	53,039	485	(485)	465,142	53,039	$ 19.01	$ 13.74	728,496	8,842,251	-	8,113,755
November	2021	665,983	6,741	7,480	(7,480)	673,463	6,741	$ 19.76	$ 12.41	83,677	13,306,869	-	13,223,193
Total		3,752,576	1,461,782	(43,545)	43,545	3,775,117	1,527,867			$ 23,513,124	$ 76,036,696	$ 5,898,495	$ 58,422,067

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 8**

North Carolina Annual Fuel and Fuel Related Expense

Projected Sales

Billing Period December 1, 2020 - November 30, 2021

Docket No. E-2, Sub 1250

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC Retail			
Residential	16,171,290		16,171,290
Small General Service	1,784,993		1,784,993
Medium General Service	10,287,749		10,287,749
Large General Service	9,128,353		9,128,353
Lighting	377,978		377,978
NC Retail	37,750,364		37,750,364
SC Retail	6,692,489	43,684	6,736,173
Total Wholesale	17,041,448		17,041,448
Total Adjusted NC System Sales	61,484,301	43,684	61,527,985
NC as a percentage of total	61.40%	0.00%	61.35%
SC as a percentage of total	10.88%	100.00%	10.95%
Wholesale as a percentage of total	27.72%	0.00%	27.70%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		43,684	
Marginal Fuel rate per MWh for SC NEM	$	22.62	
Fuel Benefit to be directly assigned to SC	$	987,955	
System Fuel Expense	$	1,314,459,781	Exh 2 Sch 1 Pg 1
Fuel benefit to be directly assigned to SC Retail		987,955	
Total Adjusted System Fuel Expense	$	1,315,447,736	Exh 2 Sch 1 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Normalized Sales
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Harrington Workpaper 9

	Test Period Sales MWhs	Weather Normalization	Customer Growth	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC Retail					
Residential	15,760,190	330,167	101,073		16,191,429
Small General Service	1,931,559	(154,700)	809		1,777,668
Medium General Service	11,028,202	(60,460)	(18,408)		10,949,334
Large General Service	8,587,442	(6,422)	3,976		8,584,996
Lighting	348,533	0	911		349,444
NC Retail	37,655,926	108,585	88,359		37,852,870
SC Retail	6,234,427	3,683	772	43,684	6,282,566
Total Wholesale	17,875,203	299,596	109,141		18,283,941
Total Adjusted NC System Sales	61,765,556	411,864	198,273	43,684	62,419,377
NC as a percentage of total	60.97%				60.64%
SC as a percentage of total	10.09%				10.07%
Wholesale as a percentage of total	28.94%				29.29%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs		43,684	
Marginal Fuel rate per MWh for SC NEM	$	22.62	
Fuel Benefit to be directly assigned to SC	$	987,955	
System Fuel Expense	$	1,342,633,059	Exh 2 Sch 2 Pg 1
Fuel benefit to be directly assigned to SC Retail		987,955	
Total Adjusted System Fuel Expense	$	1,343,621,014	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, 2020
Docket No. E-2, Sub 1250

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		373,365	88.43	330,167	11.57	43,198
	Commercial						
2	Small and Medium General Service		(176,015)	87.89	(154,700)	12.11	(21,315)
	Industrial						
3	Large General Service		(78,438)	77.08	(60,460)	22.92	(17,978)
	OPA						
4	Other Public Authority (Large General Service)		(6,644)	96.66	(6,422)	3.34	(222)
5	Total Retail	L1+ L2+ L3 + L4	112,268		108,585		3,683
6	Wholesale		299,596				
7	Total Company	L5 + L6	411,864		108,585		3,683

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, 2020
Docket No. E-2, Sub 1250

Harrington Workpaper 9b

		Residential MWH Adjustment	Commercial MWH Adjustment	Industrial MWH Adjustment	OPA MWH Adjustment	Total Retail MWH Adjustment	Wholesale MWH Adjustment
April	2019	(47,166)	-	(19,260)	-	(66,426)	-
May	2019	(92,074)	(31,596)	(55,583)	-	(179,253)	(130,288)
June	2019	(162,445)	(72,838)	(13,276)	(5,613)	(254,173)	(122,615)
July	2019	(41,116)	(14,214)	(6,989)	(1,351)	(63,670)	(35,949)
August	2019	(159,945)	2,079	997	236	(156,632)	3,596
September	2019	(51,257)	(26,965)	(8,430)	(3,053)	(89,706)	(32,160)
October	2019	(15,298)	(93,582)	(71,735)	2,686	(177,929)	(5,988)
November	2019	123,099	-	68,523	(6,142)	185,480	(27,820)
December	2019	(14,980)	-	-	-	(14,980)	(8,607)
January	2020	340,724	46,118	18,365	1,428	406,634	377,434
February	2020	368,467	14,983	8,951	5,165	397,566	98,166
March	2020	125,358	-	-	-	125,358	183,827
12ME March	**2020**	**373,365**	**(176,015)**	**(78,438)**	**(6,644)**	**112,268**	**299,596**

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 9c**
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment - MWh
Twelve Months Ended March 31, 2020
Docket No. E-2, Sub 1250

Rate Schedule	Estimation Method[1]	Reference	NC Proposed MWH Adjustment	SC Proposed MWH Adjustment	Wholesale Proposed MWH Adjustment
Residential	Regression	RES	101,073	7,614	
General:					
General Service Small	Regression	SGS	809	(3,246)	
General Service Medium	Customer	MGS	(18,408)	(4,248)	
Total General			(17,600)	(7,495)	
Lighting:					
Street Lighting	Regression	SLS/SLR	963	88	
Sports Field Lighting	Regression	SFLS	(28)	(7)	
Traffic Signal Service	Regression	TSS/TFS	(24)	571	
Total Street Lighting			911	653	
Industrial:					
I - Textile	Customer	LGS	-	-	
I - Nontextile		LGS	3,976	-	
Total Industrial			3,976	-	
Total			**88,359**	**772**	**109,141**

Note:
[1] Two approved methods are used for estimating the growth adjustment depending on the class/schedule:
"Regression" refers to the use of Ordinary Least Squares Regression.
"Customer" refers to the use of the Customer by Customer approach.

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales - NERC 5 year Average
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Harrington Workpaper 10

		Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC Retail				
	Residential	16,171,290		16,171,290
	Small General Service	1,784,993		1,784,993
	Medium General Service	10,287,749		10,287,749
	Large General Service	9,128,353		9,128,353
	Lighting	377,978		377,978
NC Retail		37,750,364		37,750,364
SC Retail		6,692,489	43,684	6,736,173
Total Wholesale		17,041,448		17,041,448
Total Adjusted NC System Sales		61,484,301	43,684	61,527,985
NC as a percentage of total		61.40%	0.00%	61.35%
SC as a percentage of total		10.88%	100.00%	10.95%
Wholesale as a percentage of total		27.72%	0.00%	27.70%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs		43,684	
Marginal Fuel rate per MWh for SC NEM	$	22.62	
Fuel Benefit to be directly assigned to SC	$	987,955	
System Fuel Expense	$	1,353,645,182	Exh 2 Sch 3 Pg 1
Fuel benefit to be directly assigned to SC Retail		987,955	
Total Adjusted System Fuel Expense	$	1,354,633,137	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, 2019
Docket No. E-2, Sub 1250

Harrington Workpaper 11

Generator Step Up Loss % 0.2598%

	kWh @ Meter	E-2 Allocation	kWh @ Prod Out.	E-1 Allocation	Losses
NC RES	15,557,072,996	24.8962%	16,083,699,023	25.0316%	526,626,027
NC RES-TOU	457,186,509	0.7316%	472,662,834	0.7356%	15,476,325
NC SGS	1,911,356,256	3.0588%	1,976,046,533	3.0754%	64,690,277
NC SGS-CLR	42,422,798	0.0679%	43,858,862	0.0683%	1,436,064
NC MGS-TOU	8,291,668,009	13.2693%	8,563,872,766	13.3283%	272,204,757
NC MGS	2,734,407,266	4.3759%	2,825,508,571	4.3974%	91,101,305
NC SI	45,974,741	0.0736%	47,418,978	0.0738%	1,444,237
NC LGS	1,999,602,174	3.2000%	2,057,691,470	3.2025%	58,089,296
NC LGS-TOU	1,649,408,743	2.6396%	1,696,853,732	2.6409%	47,444,989
NC LGS-RTP	4,894,034,278	7.8320%	5,020,914,781	7.8142%	126,880,503
NC TSS	4,658,562	0.0075%	4,816,260	0.0075%	157,698
NC ALS	263,810,754	0.4222%	272,741,072	0.4245%	8,930,318
NC SLS	85,413,048	0.1367%	88,304,385	0.1374%	2,891,337
NC SFLS	1,212,944	0.0019%	1,247,975	0.0019%	35,031
Total NCR	37,938,229,078	60.7131%	39,155,637,242	60.9393%	1,217,408,164
NCWHS incl . NCEMPA	18,048,949,589	28.8840%	18,400,231,291	28.6369%	351,281,702
Total NC	55,987,178,667	89.5971%	57,555,868,532	89.5763%	1,568,689,866
SC RES	2,041,645,412	3.2673%	2,110,757,617	3.2850%	69,112,205
SC RET	37,532,506	0.0601%	38,803,027	0.0604%	1,270,521
SC SGS	266,135,397	0.4259%	275,134,446	0.4282%	8,999,049
SC SGS-CLR	5,564,551	0.0089%	5,752,918	0.0090%	188,367
SC MGS-TOU	1,114,320,548	1.7833%	1,150,706,004	1.7909%	36,385,456
SC MGS	515,294,860	0.8246%	532,253,124	0.8284%	16,958,264
SC SI	21,354,052	0.0342%	22,015,710	0.0343%	661,658
SC LGS	686,375,801	1.0984%	706,361,216	1.0993%	19,985,415
SC LGS-TOU	294,080,086	0.4706%	301,694,491	0.4695%	7,614,405
SC LGS-CRTL-TOU	687,515,490	1.1002%	703,467,652	1.0948%	15,952,162
SC LGS-RTP	553,274,261	0.8854%	566,681,217	0.8819%	13,406,956
SC TSS	1,165,287	0.0019%	1,204,733	0.0019%	39,446
SC ALS	61,651,870	0.0987%	63,738,862	0.0992%	2,086,992
SC SLS	16,263,098	0.0260%	16,813,624	0.0262%	550,526
SC SFLS	152,093	0.0002%	156,486	0.0002%	4,393
Total SCR	6,302,325,312	10.0857%	6,495,541,126	10.1092%	193,215,814
SCWHS	198,212,014	0.3172%	202,069,760	0.3145%	3,857,745
Total SC	6,500,537,326	10.4029%	6,697,610,886	10.4237%	197,073,560
Total System	62,487,715,993	100.0000%	64,253,479,418	100.0000%	1,765,763,426

Cost of Service Data Summarized

	kWh @ Meter	kWh @ Generator	Losses (kWh)	Loss Percent
Residential	16,014,259,505	16,599,480,986	585,221,481	3.6540%
SGS	1,953,779,054	2,029,994,808	76,215,754	3.9010%
MGS	11,072,050,016	11,466,586,138	394,536,122	3.5630%
LGS	8,543,045,195	8,798,314,654	255,269,459	2.9880%
Lighting	355,095,308	363,236,983	8,141,675	2.2930%
Total NC Retail	37,938,229,078	39,257,613,570	1,319,384,492	3.4780%
Total NC Retail	37,938,229,078	39,257,613,570	1,319,384,492	3.4780%
SC Retail	6,302,325,312	6,512,458,012	210,132,700	3.3340%
12ME NEM Generation	28,276,884	29,219,635	942,751	3.3340%
Total SC Retail	6,330,602,196	6,541,677,647	211,075,451	3.3340%
All other jurisdications	18,218,884,719	18,621,528,957	402,644,238	2.2100%
Total System	62,487,715,993	64,420,820,174	1,933,104,181	3.0940%
SC Retail + All Other	24,549,486,915	25,163,206,604	613,719,689	2.5000%

Line Loss Calculations for Projected Fuel Costs	**MWh @ Meter**	**MWh @ Generator**	**Losses (MWh)**	**Loss Percent**
Total NC Retail	37,750,364	39,110,632	1,360,268	3.6030%
Total SC Retail	6,736,173	6,968,503	232,330	3.4490%
All other jurisdications	17,041,448	17,426,575	385,127	2.2600%
Total System	61,527,985	63,505,710	1,977,725	3.2140%
Allocation percent - NC retail	61.35%	61.59%		

Line Loss Calculations for Normalized Test Period Sales	**MWh @ Meter**	**MWh @ Generator**	**Losses (MWh)**	**Loss Percent**
Total NC Retail	37,852,870	39,216,832	1,363,961	3.6030%
Total SC Retail	6,282,566	6,499,251	216,685	3.4490%
All other jurisdications	18,283,941	18,697,147	413,207	2.2600%
Total System	62,419,377	64,413,230	1,993,853	3.1940%
Allocation percent - NC retail	60.64%	60.88%		

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, 2020
Docket No. E-2, Sub 1250

Harrington Workpaper 11

									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 2019 EE Rate (11) per RMCRY14	Opt-Out Credit Due to Jan. 2019 DSM Rate (12) per RMCRY15	NC Rate Case - Mar. 16, 2018 (13) per Report PMCM7M Worksheet	REPS Revenue Due to December 2018 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 1/19 EE Rate (17) = (3) * Rate Change	Annual Opt-Out Impact of 1/19 EE Rate (18) = (4) * Rate Change	NC Rate Case - Mar. 16, 2018 (19) per Report PMCM7M Worksheet	Annual Impact of Dec. 2018 REPS Rate (20) = (8) * Rate Change	Annual Revenue At Current Rates (21)=(15)+[16-17-18]+(19)+(20)
Residential	15,826,067,908	0	0	15,003,443	15,826,067,908	0	14,903,338	$1,850,837,644	$3,649,966	$0	$0	$0	$126,400	$1,847,061,277	($42,888,954)	$0	$0	$0	$447,100	$1,804,619,423
Residential	15,760,184,214	0	0	14,888,547	15,760,184,214	0	14,822,496	$1,828,445,916	$3,635,856	$0	$0	$0	$125,722	$1,824,684,339	($42,684,737)	$0	$0	$0	$444,675	$1,782,444,277
SGS	7,465	0	0	15	7,465	0	0	$1,079	($0)	$0	$0	$0	$0	$1,079	($31)	$0	$0	$0	$0	$1,048
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	65,876,229	0	0	114,881	65,876,229	0	80,842	$22,390,648	$14,111	$0	$0	$0	$678	$22,375,859	($204,187)	$0	$0	$0	$2,425	$22,174,098
Commercial	12,241,712,019	4,057,787,437	4,124,140,496	2,494,555	2,171,982,476	30,502,353	2,389,841	$1,144,805,570	$1,053,475	$2,115,868	$76,665	$0	$197,252	$1,145,747,376	($36,654,162)	($3,121,230)	$493,433	$47	$693,054	$1,112,414,111
Residential	5,509	0	0	18	44,256,161	0	0	$842	$2	$0	$0	$0	$2	$839	($14)	$0	$0	$47	$0	$871
SGS	1,909,010,606	17,750,189	18,118,924	2,035,461	46,659,770	0	1,838,482	$239,114,595	$379,221	$10,088	$27	$0	$151,438	$238,594,051	($7,721,434)	($13,668)	$2,174	$0	$533,160	$231,417,270
MGS	9,022,287,757	2,917,960,154	3,013,628,814	443,550	1,872,697,814	28,245,043	398,315	$770,720,503	$278,505	$1,554,521	$58,805	$0	$33,029	$772,022,295	($27,228,636)	($2,246,829)	$361,635	$0	$115,511	$746,794,365
LGS	1,100,830,370	1,110,410,133	1,080,192,292	1,128	0	2,257,309	896	$83,680,162	$349,222	$551,422	$17,472	$0	$73	$83,899,761	($1,055,506)	($855,016)	$129,623	$0	$260	$83,569,908
Lighting	209,577,777	11,666,961	12,200,466	14,398	208,368,731	0	152,147	$51,289,468	$46,525	($163)	$361	$0	$12,711	$51,230,430	($648,573)	($5,717)	$0	$0	$44,123	$50,631,696
Industrial	8,117,274,041	8,544,593,139	8,553,336,263	41,474	34,781,711	18,577,624	21,739	$527,079,589	$2,011,114	$4,530,531	$162,457	$0	($84,686)	$529,846,148	($11,694,279)	($6,577,154)	$1,025,425	$0	($295,433)	$523,408,164
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	18,223,753	8,285,186	8,430,827	12,006	18,223,753	0	3,366	$2,061,011	$3,115	$4,976	$181	$0	($12,974)	$2,076,028	($73,087)	($6,380)	$1,012	$0	($45,745)	$1,962,563
MGS	2,005,914,289	1,589,377,061	1,593,677,836	26,876	2,154,677	5,769,269	7,481	$159,774,604	$64,971	$851,374	$31,176	$0	($29,734)	$160,621,918	($5,859,489)	($1,223,820)	$191,241	$0	($101,670)	$155,693,338
LGS	6,078,732,718	6,939,134,462	6,943,100,364	2,397	0	12,808,355	9,344	$362,377,301	$1,939,801	$3,674,284	$131,099	$0	($36,563)	$364,279,446	($5,717,395)	($5,343,134)	$833,172	$0	($126,988)	$362,945,025
Lighting	14,403,281	7,796,430	8,127,236	195	14,403,281	0	1,547	$2,866,674	$3,228	($103)	$0	$0	($5,414)	$2,868,756	($44,308)	($3,820)	$0	$0	($21,030)	$2,807,238
Public Streets & Highways	62,991,044	0	0	10,962	62,991,044	0	10,134	$17,375,809	$11,674	$0	$0	$0	$808	$17,363,326	($196,198)	$0	$0	$0	$2,939	$17,170,066
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	4,317,021	0	0	5,388	4,317,021	0	5,304	$436,027	$1,241	$0	$0	$0	$408	$434,378	($10,816)	$0	$0	$0	$1,538	$425,100
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	58,674,023	0	0	5,574	58,674,023	0	4,830	$16,939,781	$10,433	$0	$0	$0	$400	$16,928,948	($185,382)	$0	$0	$0	$1,401	$16,744,967
Military	1,407,880,873	1,618,414,435	1,618,414,435	48	1,920	3,382,581	39	$83,258,122	$494,857	$749,918	$25,128	$0	($165)	$83,538,476	($1,266,420)	($1,246,179)	$194,210	$0	($530)	$83,323,495
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	1,407,878,953	1,618,414,435	1,618,414,435	48	0	3,382,581	39	$83,257,895	$494,856	$749,918	$25,128	$0	($165)	$83,538,250	($1,266,415)	($1,246,179)	$194,210	$0	($530)	$83,323,275
Lighting	1,920	0	0	0	1,920	0	0	$227	$1	$0	$0	$0	$0	$226	($5)	$0	$0	$0	$0	$221
NC Retail	37,655,925,885	14,220,795,011	14,295,891,194	17,550,482	18,095,825,059	52,462,558	17,325,091	$3,623,356,734	$7,221,086	$7,396,316	$264,249	$0	$239,609	$3,623,556,603	($92,700,014)	($10,944,562)	$1,713,068	$47	$847,130	$3,540,935,260
	0	0	0	0	0	0		0	$0	0	0	0	0		0			0		
Rate Schedules (excludes REPS)																				
RES (includes RES-RECD)	15,319,053,786	0	0	14,620,619	15,319,053,786	0		$1,783,868,424	$2,822,572	$0	$0	$89,595,643	$125,723	$1,691,324,486	($33,028,325)	$0	$0	$0		$1,658,296,161
SGS	1,877,917,130	26,007,474	26,520,730	1,949,437	1,877,917,130	0		$235,152,074	$375,438	$15,024	$208	$26,071,474	$130,326	$208,590,068	($7,611,443)	($20,026)	$3,182	$0		$200,995,469
MGS	2,671,885,153	318,930,417	320,863,065	200,052	0	12,760,458		$277,388,141	($293,134)	$169,063	$4,053	$28,949,035	-$15,583	$248,920,939	($9,301,078)	($245,576)	$38,504	$0		$239,826,934
SGS-TOU	8,277,629,612	4,183,307,729	4,281,248,998	259,451	0	21,190,016		$644,287,428	$623,063	$2,234,880	$27,117	$16,402,456	-$11,254	$629,535,160	($23,332,268)	($3,221,147)	$513,750	$0		$608,910,289
LGS	1,078,881,507	1,159,358,313	1,172,391,715	1,058	0	2,287,761		$87,303,271	$354,548	$549,860	$18,086	$19,630,766	-$2,321	$67,888,224	($1,039,924)	($892,706)	$140,687	$0		$67,600,319
LGS-TOU	1,696,488,028	1,783,130,634	1,743,845,293	1,517	0	3,240,038		$124,064,025	$507,576	$1,015,855	$24,384	$3,646,942	-$1,905	$120,951,651	($1,610,401)	($1,373,011)	$209,261	$0		$120,504,999
LGS-RTP	11,093,048	11,093,048	11,093,048	13	0	37,752		$857,084	$29,916	$6,726	$236	$29,670	$0	$804,459	($84,740)	($8,542)	$1,331	$0		$726,929
LGS-RTP-TOU	5,800,979,458	6,712,456,682	6,712,456,682	985	0	12,882,695		$317,090,978	$1,891,839	$3,403,184	$130,993	$11,648,950	-$2,682	$307,087,048	($5,304,251)	($5,168,592)	$805,495	$0		$306,145,894
LGS Class	8,587,442,041	9,666,038,677	9,639,786,738	3,573	0	18,448,246		$529,315,358	$2,783,880	$4,975,624	$173,699	$34,956,327	($6,907)	$496,731,381	($8,039,315)	($7,442,850)	$1,156,774	$0		$494,978,141
Rate Class																				
Residential	15,760,189,723	0	0	14,888,565	15,804,440,375	0	14,822,496	$1,828,446,758	$3,635,857	$0	$0	$0	$125,723	$1,824,685,178	($42,684,751)	$0	$0	$47	$444,675	$1,782,445,149
SGS	1,931,558,845	26,035,375	26,549,751	2,052,870	69,208,009	0	1,847,152	$241,612,712	$383,576	$15,064	$208	$0	$138,872	$241,105,536	($7,805,368)	($20,047)	$3,186	$0	$488,952	$233,805,982
MGS	11,028,202,046	4,507,337,215	4,607,306,650	470,426	1,874,852,491	34,014,312	405,797	$930,495,107	$343,476	$2,405,894	$89,981	$0	$3,295	$932,644,212	($33,088,125)	($3,470,650)	$552,877	$0	$13,842	$902,487,703
LGS	8,587,442,041	9,667,959,030	9,641,707,091	3,573	0	18,448,246	10,279	$529,315,358	$2,783,880	$4,975,624	$173,699	$0	($36,656)	$531,717,457	($8,039,315)	($7,444,328)	$1,157,005	$0	($127,258)	$529,838,208
Lighting	348,533,230	19,463,391	20,327,702	135,048	347,324,184	0	239,367	$93,486,798	$74,298	($266)	$361	$0	$8,375	$93,404,220	($1,082,456)	($9,537)	$0	$0	$26,918	$92,358,220
	37,655,925,885	14,220,795,011	14,295,891,194	17,550,482	18,095,825,059	52,462,558	17,325,091	$3,623,356,734	$7,221,086	$7,396,316	$264,249	$0	$239,609	$3,623,556,603	($92,700,014)	($10,944,562)	$1,713,068	$47	$847,130	$3,540,935,260

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, 2020
Docket No. E-2, Sub 1250

Line No.	Description	Reference	North Carolina	South Carolina	Retail Total Company	% NC	% SC
1	Residential	Company Records	15,826,068	2,071,132	17,897,200	88.43	11.57
2	Commercial	Company Records	12,241,712	1,687,036	13,928,748	87.89	12.11
3	Industrial	Company Records	8,117,274	2,413,270	10,530,544	77.08	22.92
4	Other Public Authority	Company Records	1,407,881	48,605	1,456,486	96.66	3.34
5	Total Retail Sales subject to weather	Sum 1 through 4	37,592,935	6,220,043	43,812,978		
6	Lighting	Company Records	62,991	14,384	77,375		
7	Total Retail Sales	Line 5 + Line 6	37,655,926	6,234,427	43,890,353		

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2019 Production Demand Allocation Factors
Docket No. E-2, Sub 1250

Harrington Workpaper 14

2019 Total Production Demand	System	NC Retail	Residential	Small GS	Med GS	Lrg GS	Ltg
Rate Base	13,207,703	8,014,112	4,560,461	427,579	1,994,881	1,031,190	-
NC Retail % to Total System		60.68%	34.53%	3.24%	15.10%	7.81%	0.00%
Allocation of Classes to Total NC Retail		100.00%	56.91%	5.34%	24.89%	12.87%	0.00%

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Scenario Differences
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Exhibit 2 Schedule 1: Line Loss

Line Losses	Exh 2 Sch 1 Pg 1 Ln 16	(1,906,330)
Generation	Exh 2 Sch 1 Pg 1 Ln 10	57,521,087
	%	-3.314%
	Multiplier	1.033141

Schedule 2: Proposed Nuclear Capacity Factor & Normalized Sales

Normalized Sales	Exh 4, Total Co., Ln 4	62,375,693
Sales Forecast	Exh 2 Sch 1 Pg 1 Ln 18	61,484,301
Difference		891,392
Gross up for losses	Difference x Multiplier	920,934
	MWh changes in Coal	920,934
	MWH changes in Losses	(29,542)

	Before Adj	Adj	Total
Total Coal MWh	7,940,674	920,934	8,861,608
Total Losses MWh	(1,906,330)	(29,542)	(1,935,872)
	6,034,345	891,392	6,925,736

	Before Adj	After Adj	Adjustment
Total Coal $	$ 242,921,665	$ 271,094,943	$ 28,173,278

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

		Nuclear-MWHs	Nuclear Costs
Nuclear	WP 1	29,730,338	$ 184,443,928
Nuclear - NERC Average	WP 2	28,123,601	$ 174,475,894
	Adjustment	(1,606,738)	$ (9,968,034)

		Coal-MWH	Coal Costs	
Coal MWh	WP 3, WP4	7,940,674	$ 242,921,665	
Adjustment from Above	Adjustment above	1,606,738	$ 49,153,435	(Priced at the avg Coal $/MWH)
		9,547,412	$ 292,075,099	

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 16**
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 270,209,122	$ (9,714,001)	$ 260,495,121
2	Amount in 2019 Filing: Docket E-2 Sub 1204	281,070,708	98,879,127	379,949,835
3	Reduction in prior year docket in excess of 2.5%	-		-
4	Increase/(Decrease)	$ (10,861,586)	$ (108,593,128)	$ (119,454,714)
5	2.5% of 2019 NC revenue of $3,725,835,297			93,145,882
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases from Dispatchable Units	$ 43,444,341	61.59%	$ 26,757,369
WP 4	Purchases for REPS Compliance Energy	131,543,318	61.59%	81,017,530
WP 4	Purchases for REPS Compliance Capacity	26,962,441	60.68%	16,360,152
WP 4	Purchases from Qualifying Facilities Energy	191,949,817	61.59%	118,221,892
WP 4	Purchases from Qualifying Facilities Capacity	39,344,300	60.68%	23,873,161
WP 4	Allocated Economic Purchases	6,460,492	61.59%	3,979,017
	Total	$ 439,704,709		$ 270,209,122

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Dispatchable Purchased Energy	$ 14,160,859	61.68%	$ 8,734,418
Prior Year	Purchases for REPS Compliance Energy	168,625,939	61.68%	104,008,479
Prior Year	Purchases for REPS Compliance Capacity	34,622,728	61.00%	21,120,137
Prior Year	Purchases from Qualifying Facilities Energy	193,990,299	61.68%	119,653,216
Prior Year	Purchases from Qualifying Facilities Capacity	39,793,114	61.00%	24,274,113
Prior Year	Allocated Economic Purchases	5,318,328	61.68%	3,280,345
Prior Year	Total	$ 456,511,266		$ 281,070,708

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Normalized
Billing Period December 1, 2020 - November 30, 2021
Docket No. E-2, Sub 1250

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 266,672,371	$ (9,714,001)	$ 256,958,370
2	Amount in 2019 Filing: Docket E-2 Sub 1204	277,600,013	98,879,127	376,479,140
3	Reduction in prior year docket in excess of 2.5%	-		-
4	Increase/(Decrease)	$ (10,927,642)	$ (108,593,128)	$ (119,520,770)
5	2.5% of 2019 NC revenue of $3,725,835,297			93,145,882
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases from Dispatchable Units	$ 43,444,341	60.64%	$ 26,345,873
WP 4	Purchases for REPS Compliance	131,543,318	60.64%	79,771,578
WP 4	Purchases for REPS Compliance Capacity	26,962,441	60.68%	16,360,152
WP 4	Purchases from Qualifying Facilities Energy	191,949,817	60.64%	116,403,782
WP 4	Purchases from Qualifying Facilities Capacity	39,344,300	60.68%	23,873,161
WP 4	Allocated Economic Purchases	6,460,492	60.64%	3,917,825
	Total	$ 439,704,709		$ 266,672,371

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Dispatchable Purchased Energy	$ 14,160,859	60.77%	$ 8,605,790
Prior Year	Purchases for REPS Compliance Energy	168,625,939	60.77%	102,476,796
Prior Year	Purchases for REPS Compliance Capacity	34,622,728	61.00%	21,120,137
Prior Year	Purchases from Qualifying Facilities Energy	193,990,299	60.77%	117,891,140
Prior Year	Purchases from Qualifying Facilities Capacity	39,793,114	61.00%	24,274,113
Prior Year	Allocated Economic Purchases	5,318,328	60.77%	3,232,037
Prior Year	Total	$ 456,511,266		$ 277,600,013

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test-Detail Calculation
Test Period April 2019 - March 2020
Docket No. E-2, Sub 1250

Harrington Workpaper 18

Line No.		Reference	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	* Dec-19	** Jan-20	Feb-20	Mar-20	9ME
1	System kWh Sales, at generation		6,468,737,186	6,380,831,838	5,974,860,872	5,105,924,864	4,553,581,442	5,276,460,182	5,306,171,314	5,041,761,389	4,713,060,944	48,821,390,032
2	NC Retail kWh Sales, at generation		3,842,248,537	3,878,902,522	3,704,042,982	3,236,522,467	2,712,147,368	3,233,250,247	3,279,885,398	3,197,824,874	2,998,084,712	30,082,909,107
3	NC Retail % of Sales	Line 2 / Line 1	59.40%	60.79%	61.99%	63.39%	59.56%	61.28%	61.81%	63.43%	63.61%	61.62%
	Total Purchase Power, Excl. JDA											
4	System Purchase Power, Excl. JDA		$ 35,556,851	$ 39,043,313	$ 35,250,052	$ 31,502,806	$ 27,075,292	$ 24,088,501	$ 24,574,160	$ 26,770,482	$ 25,291,830	$ 269,153,287
5	NC Purchase Power	Line 4 * Line 3	$ 21,119,772	$ 23,734,398	$ 21,852,845	$ 19,968,868	$ 16,126,248	$ 14,760,682	$ 15,189,941	$ 16,979,644	$ 16,088,705	$ 165,847,672
6	NC Retail kWh Sales		3,688,282,391	3,723,368,929	3,556,134,030	3,108,120,473	2,604,857,399	3,103,485,292	3,148,281,345	3,069,536,495	2,878,563,877	28,880,630,231
7	NC Incurred Rate	Line 5 / Line 6 * 100	0.573	0.637	0.615	0.642	0.619	0.476	0.482	0.553	0.559	0.574
	Total Capacity											
8	System Capacity		$ 13,242,560	$ 13,425,999	$ 10,199,593	$ 4,988,974	$ 4,601,300	$ 3,750,610	$ 4,806,509	$ 4,966,513	$ 3,670,419	$ 63,652,477
9	NC Capacity (Avg Monthly NC % of System Sales for the Period Presented on WP 18)	61.24%	$ 8,109,483	$ 8,221,817	$ 6,246,029	$ 3,055,149	$ 2,817,746	$ 2,296,799	$ 2,943,411	$ 3,041,395	$ 2,247,692	$ 38,979,522
10	NC Incurred Rate	Line 9/Line 6*100	0.220	0.221	0.176	0.098	0.108	0.074	0.093	0.099	0.078	0.135
11	Total NC Incurred Rate	Line 7 + Line 10	0.792	0.858	0.790	0.741	0.727	0.550	0.576	0.652	0.637	0.709
12	Billed Rate	Billed Rates Below	0.747	0.747	0.747	0.747	0.747	0.742	0.734	0.734	0.734	
13	(Over)/Under cents per kwh	Line 131- Line 12	0.045	0.111	0.043	(0.007)	(0.020)	(0.193)	(0.159)	(0.082)	(0.097)	
14	(Over)/Under $	Line 6 * Line 13 /100	$ 1,663,127	$ 4,127,852	$ 1,520,420	$ (205,995)	$ (524,644)	$ (5,975,358)	$ (4,990,334)	$ (2,523,523)	$ (2,805,545)	$ (9,714,001)

Billed Rate from Docket E-2, Sub 1173 - Jul'19-Nov'19

15	Purchases from Dispatchable Units & Economic Purchases	91,098,502	2018 Ward WP4
16	Total MWH Sales	68,667,857	2018 Ward WP3
17	Billed Rate for Purchases	**0.133**	
18	Renewables (energy)	187,595,597	2018 Ward WP4
19	Total MWH Sales	68,667,857	2018 Ward WP3
20	Billed Rate for Renewables	**0.273**	
21	QF Purchases (energy)	162,649,793	2018 Ward WP4
22	Total MWH Sales	68,667,857	2018 Ward WP3
23	Billed Rate for Renewables	**0.237**	
24	Capacity (REPS and QF)	71,877,910	2018 Ward WP4
25	Total MWH Sales	68,667,857	2018 Ward WP3
26	Billed Rate for Capacity	**0.105**	
27	Total Billed Rate	**0.747**	To Line 12

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

	Prior Bill Rate (Sub 1173)	New Bill Rate (Sub 1204)	December Blended Rate	
Approved Rates	0.747	0.734		
Ratios of Days to rate	59.52%	40.48%		
Prorated Rate	**0.445**	**0.297**	**0.742**	To Line 12

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

	Prior Bill Rate (Sub 1173)	New Bill Rate (Sub 1204)	January Blended Rate	
Approved Rates	0.747	0.734		
Ratios of Days to rate	0.190%	99.81%		
Prorated Rate	**0.001**	**0.733**	**0.734**	To Line 12

Billed Rate from Docket E-2, Sub 1204 - Dec'19-Mar'20

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**REGIS REPKO 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 Regis Repko 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 and Chief Fossil/Hydro Officer for Duke Energy Progress, LLC ("DEP" or the "Company").

Q. WHAT ARE YOUR CURRENT DUTIES AS SENIOR VICE PRESIDENT AND CHIEF FOSSIL/HYDRO OFFICER?

A. In this role, I am responsible for the operations of the Company's regulated fleet of fossil, hydroelectric, and solar (collectively, "Fossil/Hydro/Solar") generating facilities in six states, including outage and maintenance services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Pennsylvania State University with a Bachelor of Science degree in Nuclear Engineering. My career began with Duke Energy in 1995 as an engineer at Oconee Nuclear Station. I have held various roles of increasing responsibility including nuclear shift supervisor, operations shift manager, engineering supervisor, maintenance rotating equipment manager, and superintendent of operations, where I had responsibility for the operations of Oconee Nuclear Station and Keowee Hydro Station. I have also served as engineering manager for Catawba Nuclear Station and station manager for McGuire Nuclear Station. I became the Senior Vice President and Chief Fossil/Hydro Officer in 2016.

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

A. Yes. I testified before this Commission in the DEP NC 2019 Fuel Hearing Docket E-2, Sub 1204.

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 2019 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, 2019 through March 31, 2020 (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 8,933 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	3,166 MWs
Combustion Turbines -	2,437 MWs
Combined Cycle Turbines -	3,054 MWs
Hydro -	227 MWs
Solar -	49 MWs[1]

[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.

The 3,166 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 ("NO_x"), flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"), and low NO_x 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 2,183 MWs, or 90% 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 3,634 MWs shown as "Combined Cycle Turbines" ("CC") represent six power blocks. The H. F. Lee 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 nine 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 227

MWs of capacity. The Company's solar fleet consists of four sites providing 49 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. Asheville CC commissioned its first power block in December 2019, which increased its capacity by 237 MWs. The CT of the second Asheville CC power block came on-line in January 2020, which increased capacity by 153 MW. The steam turbine component of the second Asheville CC power block came on-line in April 2020. The total Asheville CC capacity is 474 MWs. The Asheville Units 1 and 2 coal-fired generation retired in January 2020, which reduced capacity by 378 MWs. Darlington CT Units 1, 2, 3, 4, 6, 7, 8, and 10 were retired March 2020, which reduced capacity by 379 MWs.

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 27% of the Fossil/Hydro/Solar generation, with the average heat rate for the coal-fired units being 10,872 Btu/kWh. The most active station during this period was Roxboro, providing 94% of the coal production for the fleet with a heat rate of 10,529 Btu/kWh. During the review period, the Company's combined cycle power blocks produced 62% of the Fossil/Hydro/Solar generation, with an average heat rate of 7,242 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 59,980,947 megawatt-hours ("MWHs"), of which 31,119,615 MWHs, or approximately 52%, was provided by the Fossil/Hydro/Solar fleet. The breakdown includes a 36% contribution from gas facilities, 14% contribution from coal-fired stations, 1.1% 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 62% 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.

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 2014 through 2018. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating.

Generator Type	Measure	Review Period	2014-2018	Nbr of Units
		DEP Operational Results	NERC Average	
Coal-Fired Test Period	EAF	76.3%	80.7%	399
	NCF	27.1%	56.3%	
	EFOR	5.5%	8.6%	
Coal-Fired Summer Peak	EAF	91.8%	n/a	n/a
Total CC Average	EAF	81.6%	84.9%	333
	NCF	66.0%	53.6%	
	EFOR	0.77%	5.1%	
Total CT Average	EAF	82.7%	87.5%	750
	SR	98.7%	98.3%	
Hydro	EAF	64.9%	80.2%	1,063

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 3 had a planned outage in Spring 2019. The primary purpose of the outage was to perform a boiler inspection. Roxboro Unit 1 had a planned outage in Fall 2019. The outage scope included air heater basket and gearbox replacements, FGD inspections and repairs, high energy piping inspections, and replacement of the vibration sensing equipment to the turbine.

The CC fleet performed planned outages at Richmond County CC PB5 and Lee CC in Spring 2019. The primary purposes of the Richmond CC PB5 outage was to perform a major hot gas path inspection, conduct a steam turbine overhaul, generator rewind, high energy piping inspection, and heat recovery steam generator ("HRSG") inspection. The primary purposes of the Lee CC's full block maintenance was to perform a HRSG inspection, clean SCRs/condenser, and install new distributive control system upgrade.

The CT fleet performed planned outages in the Spring and Fall of 2019. In Spring 2019, Darlington CT Unit 13 performed a planned outage, the primary purpose was to perform a hot gas path inspection and boroscope inspection. In the Fall of 2019, Asheville CT Unit 4 performed a planned outage, the primary purpose was to upgrade the distributive control systems. Also, in the Fall of 2019, Richmond County CT Unit 6 performed an outage to complete GT rotor replacement and generator rewind.

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.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

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, 2019 through March 31, 2020 test period ("test period"), and (3) describe changes forthcoming for the December 1, 2020 through November 30, 2021 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 $47.93 per pound for uranium concentrates during the test period, representing an increase of 16% per pound from the prior test period. This increase was primarily due to the purchase of low cost uranium available in the spot market during 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 decreased 22% to $76.63 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 – 18% and 5%, respectively, for the fuel batches recently loaded into DEP's reactors – of DEP's total direct fuel cost relative to uranium concentrates or enrichment, which each represent 41% and 36%, 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 a slight change in nuclear fuel costs 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 is expected to increase from 0.609 cents per kWh incurred in the test period, to approximately 0.620 cents per kWh in the billing period.

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

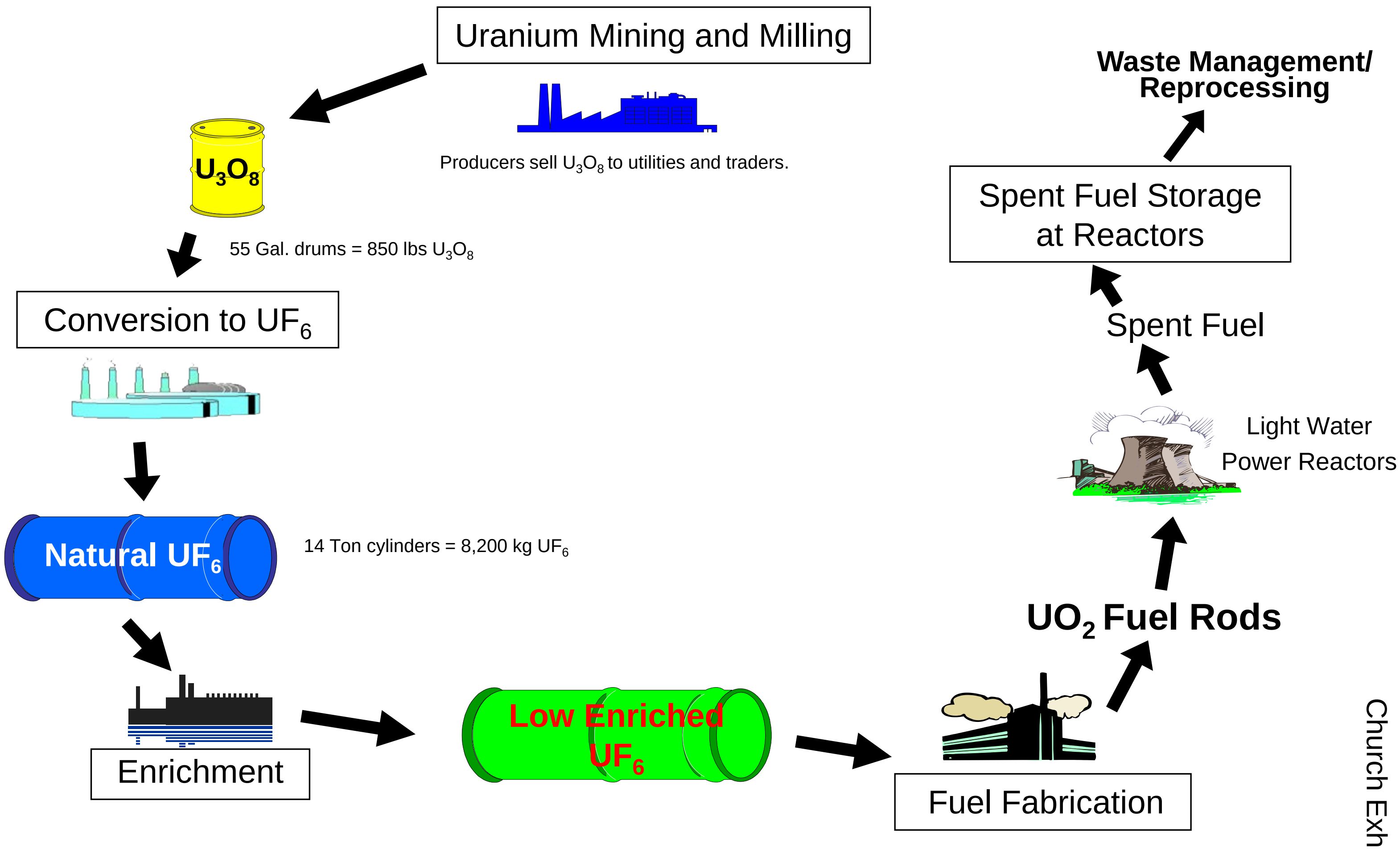
A. As I discussed earlier and as described in Church Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEP relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating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



Church Exhibit 1

Duke Energy Progress, LLC Nuclear Fuel Procurement Practices

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

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**KELVIN HENDERSON 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 Kelvin Henderson 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 Mechanical Engineering from Bradley University and over 28 years of nuclear energy experience with increasing responsibilities. My nuclear career began at Commonwealth Edison's Zion Nuclear Station in Illinois where I received a senior reactor operator license from the Nuclear Regulatory Commission ("NRC") and served as a control room unit supervisor. In 1998, I joined Progress Energy in the operations department at the Harris Nuclear Station. After serving in various leadership roles in Operations, Work Management, and Maintenance, I was named plant manager at Harris. In 2011, I was named General Manager of nuclear fleet operations for Progress Energy. Following the Duke Progress merger in 2012, I became site Vice President of DEC's Catawba Nuclear Station in York County, South Carolina. In 2016, I was named Senior Vice President of Corporate Nuclear, and I assumed my current role as Senior Vice President of Nuclear Operations in December 2017.

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

A. Yes, I filed testimony in DEP's 2018 and 2019 fuel proceedings (Docket Nos. E-2, Sub 1173 and E-2, Sub 1204, respectively) and DEP's 2019 general rate case (Docket No. E-2, Sub 1219).

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, 2019 through March 31, 2020 (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, 2020 through November 30, 2021 ("billing period").

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

A. Henderson Exhibit 1 is a confidential exhibit outlining the planned schedule for refueling outages for DEP's nuclear units for the period of April 1, 2020 through November 30, 2021. 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, 2020.

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. Yes. During the fall 2018 Robinson refueling outage, both low pressure turbines were replaced with a new design. After analysis, testing, and observation in both the winter and summer periods of 2019, the Robinson maximum dependable capacity was increased from 741 MWs to 759 MWs effective January 1, 2020, a gain of 18 MWs. The winter capability rating was decreased to 792.9 MWs also effective January 1, 2020, a decrease of 4.1 MWs from the prior winter rating.

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 48% of the total power generated by DEP. The four nuclear units operated at an actual system average capacity factor of 91.79% during the test period, which included three refueling outages. Additionally, for the second consecutive year, both Brunswick units were removed from service in response to expected hurricane force winds. Hurricane Dorian resulted in Brunswick Unit 1 being offline for 3.8 days and Unit 2 for 2.3 days.

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. The most recently published North American Electric Reliability Council's ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") indicates an industry average capacity factor of 92.72% for comparable units for the five-year period of 2014 through 2018. During the same five-year period, DEP's nuclear fleet achieved an average capacity factor of 92.93%.

The Company's test period capacity factor of 91.79%[2] fell just below the industry five-year average. The two-year average capacity factor of 90.50% also fell below the NERC 5-year average.

Q. NOTWITHSTANDING THE FACT THAT THE COMPANY FAILED TO MEET THE NERC 5-YEAR AVERAGE CAPACITY FACTOR DURING THE TEST PERIOD, WAS THE COMPANY PRUDENT IN ITS OPERATIONS OF ITS NUCLEAR FLEET DURING THE TEST PERIOD?

A. Yes. As is described in more detail below, the Company has managed its nuclear fleet in a prudent manner during the test period, and the unplanned outages that occurred were due to circumstances outside of the Company's control.

Q. PLEASE PROVIDE BACKGROUND ON THE MOST SIGNIFICANT UNPLANNED OUTAGE OCCURING DURING THE TEST PERIOD.

A. The most significant unplanned outage impact to the Company's test year capacity factor resulted from a 23-day forced outage at the Robinson plant. On August 11, 2019, while operating at 100% power, the Robinson plant experienced a main generator lockout resulting in a turbine trip and subsequent reactor trip. Investigation determined the main generator exciter had failed. The failure of the exciter occurred suddenly, with no prior indication of problems. The exciter was installed in 2008 and had received a thorough periodic 10-year vendor inspection in 2017 that noted no

[2] In Docket No. E-2, Sub 1204, Public Staff questioned the Company's capacity factor calculation when a unit's MDC value based on the difference between the point in time at which a modification is made that will result in increased capacity and the point at time at which the Company has formally verified the change in capacity through actual operation consistent with industry practices. The test period capacity factor conveyed in testimony aligns with Company and industry norms and guidance; however, the Company agreed to satisfy the Public Staff's request for recalculation. Between late fall 2018 and January 1, 2020, the performance capabilities of new low-pressure turbines installed at the Robinson plant were evaluated over the course of a summer and winter peak season before the rating was declared effective. Based on Public Staff's position, DEP's test period capacity factor would be 91.45%.

significant deficiencies. The Company's post-event investigation determined that all subsequent Company-led inspections and preventive and corrective maintenance were performed correctly and in accordance with plant procedures, industry standards and vendor guidance. Due to the significant damage to the exciter, evidence that could pinpoint the exact cause of the failure was destroyed and no definitive cause of the failure could be determined. The investigation, with participation of both Company and vendor experts, revealed that the most likely cause was a latent failure of the exciter armature due to either coil or core failure. The investigation ruled out any foreign material, human performance shortfalls, or programmatic issues that contributed to the failure. The exciter was replaced, and the unit returned to service on September 3, 2019. Failure of a main generator exciter of this age with no prior observed failure indications is extremely rare. The outage was unpredictable and therefore, unpreventable.

Q. PLEASE DESCRIBE THE HURRICANE-RELATED OUTAGE IMPACTS TO THE BRUNSWICK NUCLEAR PLANT.

A. As I mentioned earlier in my testimony, for the second consecutive year, both Brunswick units were impacted by hurricanes: Florence in 2018 and Dorian in 2019. In September 2019, Brunswick units were removed from service prior to the expected arrival of Hurricane Dorian. Brunswick Unit 2 returned to service on September 7, 2019 followed by Unit 1 on September 9, 2019.

Q. WHAT IMPACTS DID THE HURRICANE RELATED OUTAGES AT BRUNSWICK AND THE EXCITER OUTAGE AT ROBINSON HAVE ON

DEP'S ABILITY TO MEET THE NERC 5-YEAR CAPACITY FACTOR AVERAGE?

A. Excluding the Robinson outage caused by the unforeseeable exciter failure and the Brunswick outages attributable to Hurricane Dorian, the Company would have achieved a test period capacity factor of 93.56%,[3] which exceeds the NERC 5-year average of 92.72%. The Company believes that this provides evidence that it operated its nuclear plants in a safe, effective, and prudent manner throughout the test period.

Q. WERE THERE OTHER UNPLANNED OUTAGES DURING THE TEST PERIOD?

Yes. In the spring of 2019, Brunswick Unit 1 was forced offline for a total of 19 days (two events) due to an instrument line coupling failure in the unit's drywell. Investigation of the coupling failure determined that the specific material of the couplings was susceptible to embrittlement in environments with high levels of hydrogen combined with high temperatures. The vendor nor the industry engineering community was aware of this susceptibility in the early 1980's when the couplings were installed. Brunswick Unit 2 was preparing to exit from a planned refueling outage when the Unit 1 forced outage occurred. The coupling failure on Unit 1 necessitated extent of condition inspections and replacements of similar couplings on

[3] Applying the same methodology explained in footnote 2 and excluding the exciter failure outage at Robinson and the Hurricane Dorian outages at Brunswick, the test period capacity factor would be 93.20%, which exceeds the NERC 5-year average of 92.72%.

Unit 2 before the refueling outage could conclude. This work extended the Unit 2 refueling outage by 10 days.

The spring 2020 Brunswick Unit 1 refueling outage was extended three days when a safety relief pilot valve failed during testing. The investigation into the cause of the valve failure is currently in process.

Harris was forced offline for two days when planned maintenance resulted in an automatic reactor trip. Investigation determined that all plant procedures were followed correctly but that the plant procedures were based on erroneous information provided in the vendor guidance. Henderson Exhibit 2 provides a summary of the unplanned outages during the test period.

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. 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, 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 three refueling outages completed during the test period: Brunswick 2 in the spring of 2019, Harris in the fall of 2019, and Brunswick 1 during the spring of 2020.

Brunswick Unit 2 was disconnected from the grid for refueling on March 2, 2019. In addition to refueling, safety and reliability enhancements were completed during the outage. Projects to replace the aging original feedwater heaters continued with the replacement of the 3A and 3B feedwater heaters during the outage. These replacements improve system reliability and reduce maintenance costs. Replacement of all 20 original feedwater heaters is scheduled to be completed by the spring of 2028. Fouled feedwater venturis were also replaced, improving accuracy of feedwater flow measurement and increasing efficiency of the system and unit. The main turbine electro-hydraulic control system was replaced with a modern digital turbine control system. This replacement eliminates several single-point vulnerabilities, addresses aging and obsolescence issues, and reduces the likelihood of unplanned turbine trips. The 2A and 2B reactor recirculation pump seals were replaced with an improved design. The new design, first installed on the Unit 1 "B" pump in 2018, have performed as designed and are providing improved reliability.

The refueling outage for Unit 2 extended 10 days beyond allocation due to issues with a turbine bearing and required extent of condition inspections after Unit 1 experienced a drywell leak associated with a failed instrument coupling that I mentioned earlier in my testimony. As the Company was placing the turbine in service and preparing to exit the outage, an unanticipated failure of a turbine bearing occurred. While addressing the bearing issue, the Unit 1 coupling failure occurred. The Company was required to inspect and replace similar couplings on Unit 2 before returning the unit to service. After refueling, required maintenance, and inspections were completed, the unit returned to service on April 13, 2019. The turbine was removed from service for just over an hour to complete turbine overspeed testing. The outage duration was 42 days compared to a scheduled allocation of 32 days.

Harris shut down for scheduled refueling on October 12, 2019. Maintenance activities, safety enhancements, and inspections were completed as the unit was refueled. Significant projects completed included the replacement of the unit's reactor vessel head, resolving the susceptibly of stress corrosion cracking and reducing O&M costs and time required for inspections and repairs. Main generator work completed included stator re-wedge and rotor insulator repairs. Large pump and motor refurbishments and replacements included the 'B' essential chiller compressor and motor, 'B' emergency service water pump and motor, 'B' condensate pump and motor, and the 'B' heater drain pump motor. Steam generator, main generator, and exciter inspections were completed. After refueling, modifications, maintenance, and inspections were completed, the unit returned to service on November 18, 2019. The outage duration was 37.6 days versus a scheduled allocation of 39 days.

Brunswick Unit 1 entered a scheduled refueling outage on February 29, 2020. In addition to refueling activities, routine maintenance, safety and reliability enhancements, and required inspections were completed. Major work completed included the replacement of reactor water cleanup heat exchanger shell side interconnecting piping, which was driven in response to industry operating experience. As part of the aged management program, four cryogenic couplings were removed and replaced. A reliability enhancement initiative continued with the replacement of the 1B reactor recirculation pump seal with a new enhanced designed. All four 125Vdc safety related batteries were replaced. Major inspections completed included main generator and exciter 10-year preventative maintenance, 1B low-pressure turbine pin and blade, and high-pressure coolant injection system 10-year preventive maintenance.

As the unit was preparing to restart following the refueling outage, a safety relief pilot valve failed during testing, extending the outage by three days beyond the 25-day schedule allocation. The investigation into the cause of the pilot valve failure is underway. The unit returned to service on March 28, 2020.

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

A. The Company proposes to use a 94.46% 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 92.72% for comparable units as reported in the NERC Brochure during the period of 2014 to 2018.

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

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

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

KELVIN HENDERSON CONFIDENTIAL EXHIBIT 1

FILED UNDER SEAL

JUNE 9, 2020

Duke Energy Progress
Unplanned Nuclear Outages
Period: April 1, 2019 through March 31, 2020

Unit	**Dates**	**Duration (Days)**	**Cause**
Brunswick 1	3/28 – 4/11/19, 4/21 – 4/27/19	19	Forced outages: Coupling failure
Brunswick 2	4/3 – 4/13/19	10	Extension of planned refueling outage: Extent of condition inspections and repairs associated with Unit 1 instrument line coupling failure that occurred on March 28,2019.
Robinson 2	8/11 – 9/3/19	23	Forced outage: Main generator exciter failure
Brunswick 1	9/5 – 9/9/2019	3.8	Forced outage: Hurricane Dorian
Brunswick 2	9/5 – 9/7/2019	2.3	Forced outage: Hurricane Dorian
Brunswick 1	3/25 – 3/28/20	3	Extension of planned refueling outage: Failure of safety relief pilot valve
Harris 1	3/23 – 3/25/20	2.2	Forced outage: Auto-Stop Trip header pressure drop resulting in automatic reactor trip

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**BRETT PHIPPS 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 Brett Phipps. 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 Managing Director, Fuel Procurement, for Duke Energy Corporation ("Duke Energy"). In that capacity, I directly manage the organization responsible for the purchase and delivery of coal and natural gas 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 "Utilities," or the "Companies"). In addition to fuels, I also supervise the procurement of all reagents.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Chemistry from Marshall University. I began in the mining industry in 1993 where I held various roles associated with surface mining operations. I joined Progress Energy in 1999, holding roles in terminal operations and sales and marketing for the unregulated business. I transitioned to the regulated utility in 2005 where I worked in various fuels procurement functions and leadership roles. I joined Duke Energy in July 2012 and am currently Managing Director, Fuels Procurement. I am on the Board of Directors of the American Coal Council, and am a member of the The Coal Institute, the Lexington Coal Exchange, Southern Gas Association, and the American Gas Association.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR

PROCEEDING?

A. Yes. I testified in support of DEP's 2019 fuel and fuel-related cost recovery application in Docket No. E-2, Sub 1204.

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, 2019 through March 31, 2020 ("test period") versus the period April 1, 2018 through March 31, 2019 ("prior test period"), and describe changes projected for the billing period of December 1, 2020 through November 30, 2021 ("billing period").

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

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Phipps Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Phipps 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 Phipps Exhibit 3, which summarizes the fuels related transactional activity between DEC and Piedmont Natural Gas Company, Inc. ("Piedmont") for spot commodity transactions during the test period, as required by the Merger Agreement between Duke Energy and Piedmont, of which DEP receives an allocated portion based on its pro rata share of the overall gas plant burns for the respective month. Lastly, Phipps Confidential Exhibit 4, summarizes the findings of the Company's review of its forecasting and hedging programs as ordered by the Commission in its *Order Approving Fuel Charge Adjustment* in Docket No. E-2, Sub 1204 ("2019 Fuel Order").

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

A. A summary of DEP's fossil fuel procurement practices is set out in Phipps 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 $86.94 per ton, compared to $84.81 per ton in the prior test period, representing an increase of approximately 3%. The cost of delivered coal is inclusive of revenues related to the sale of coal inventories following the retirement of Asheville Coal Station at the end of January 2020 as well as an average transportation cost of $31.76 per ton in the test period. The average transportation cost for the test period was $31.76 compared to $32.72 per ton in the prior test period, representing a decrease of approximately 3%. The Company's average price of gas purchased for the test period was $3.74 per Million British Thermal Units ("MMBtu"), compared to $4.05 per MMBtu in the prior test period, representing a decrease of approximately 8%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEP's coal burn of 3.6 million tons for the test period was flat to the prior test period's burn of 3.6 million tons. The Company's natural gas burn for the test period was 166.6 million MMBtu, compared to a gas burn of 182.4 million MMBtu in the prior test period, representing a decrease of approximately 9%. The net decrease in DEP's overall natural gas burn was primarily driven by gas to coal switching as a result of the new coal rail transportation rate that went into effect March 1, 2019.

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; (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 supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

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. In addition, there continues to be growth in the natural gas pipeline infrastructure needed to serve increased market demand. However, pipeline infrastructure permitting and regulatory process approval efforts are taking longer due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing.

Over the longer term planning horizon, natural gas supply is projected to continue to increase along with the needed pipeline infrastructure to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico.

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 3.3 million tons, compared to 3.6 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 $74.41 per ton for the billing period compared to $86.94 per ton in the test period. This includes an average projected total transportation cost of $28.84 per ton for the billing period, compared to $31.76 per ton in the test period. The projected cost is due, in part, to the negotiated rail transportation contracts which went into effect in March 2019. 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; (5) additional costs associated with managing inventories as a result of load reductions from the Covid-19 crisis; and (6) 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 135.0 million MMBtu, which is a decrease from the 166.6 million MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.64 per MMBtu, compared to $2.33 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

Q. WHAT STEPS IS DEP TAKING TO MANAGE PORTFOLIO FUEL COSTS?

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. Lastly, 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.

Q. AS DIRECTED IN THE 2019 FUEL ORDER, DID THE COMPANY EVALUATE HISTORIC PRICE FLUCTUATIONS AND WHETHER ITS

CURRENT METHOD OF FORECASTING AND HEDGING PROGRAMS SHOULD BE ADJUSTED TO MITIGATE THE RISK OF SIGNIFICANT UNDER-RECOVERY OF FUEL COSTS?

A. Yes. The Company performed a review as ordered by the Commission and summarized its findings. The findings of the Company's review are detailed in Phipps Confidential Exhibit 4.

Q. AS A RESULT OF THIS EVALUATION, DID THE COMPANY DETERMINE THAT ITS CURRENT METHOD OF FORECASTING OR ITS HEDGING PROGRAMS SHOULD BE ADJUSTED TO MITIGATE THE RISK OF SIGNIFICANT UNDER-RECOVERY OF FUEL COSTS?

A. No, the Company determined that no adjustments are needed to its current method of forecasting or to its physical hedging program. However, the Company continues to refine and add modeling capabilities that will provide the Company with additional information to help with analyzing fuel forecasts and needed procurement activities, and associated ranges of potential costs. Lastly, the Company recommends extending financial hedging activities for a lower percentage in rolling years four and five to mitigate cost risks for customers as explained in more detail in Phipps Confidential Exhibit 4.

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, environmental permit and emissions considerations, projected renewable capacity, and wholesale energy imports and exports.
- Station and system inventory targets are developed to provide reliability, insulation from short-term market volatility, and sensitivity 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 additional needs.
- All qualified suppliers are invited to participate in proposals to satisfy additional or contract needs.
- Spot market solicitations are conducted on an on-going basis to supplement contract purchases.
- Contracts are awarded based on the lowest evaluated offer, 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 capacity, and fleet maintenance and availability schedules.
- Physical procurement targets are developed to procure a cost effective and reliable natural gas supply.
- Over time, short-term and long-term Requests for Proposals and market solicitations are conducted with potential suppliers 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 ascertain additional 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 36-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, 2013, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for the combined Carolinas gas fleet.

Fuel Oil

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

DUKE ENERGY PROGRESS
Summary of Coal Purchases
Twelve Months Ended March 2020 & 2019
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
1	April 2019	323,887	130,272	454,159
2	May	274,199	114,353	388,552
3	June	264,904	128,425	393,329
4	July	302,124	103,008	405,132
5	August	242,562	138,879	381,441
6	September	250,947	122,036	372,983
7	October	328,185	0	328,185
8	November	423,513	12,789	436,302
9	December	388,247	0	388,247
10	January 2020	292,138	51,142	343,280
11	February	0	0	0
12	March	63,516	25,179	88,695
13	**Total** (Sum L1:L12)	**3,154,222**	**826,083**	**3,980,305**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
14	April 2018	250,213	0	250,213
15	May	229,852	0	229,852
16	June	170,145	0	170,145
17	July	281,312	25,688	307,000
18	August	316,012	24,850	340,861
19	September	280,066	74,767	354,833
20	October	230,501	83,019	313,519
21	November	166,987	74,177	241,164
22	December	60,781	259,086	319,867
23	January 2019	148,090	170,562	318,652
24	February	314,005	25,352	339,357
25	March	402,153	24,070	426,223
26	**Total** (Sum L14:L25)	**2,850,117**	**761,571**	**3,611,686**

DUKE ENERGY PROGRESS
Summary of Gas Purchases
Twelve Months Ended March 2020 & 2019
MBTUs

Line No.	Month	MBTUs
1	April 2019	12,297,990
2	May	8,937,450
3	June	12,847,001
4	July	15,401,771
5	August	15,584,187
6	September	14,570,973
7	October	13,869,892
8	November	14,862,032
9	December	13,958,980
10	January 2020	15,791,889
11	February	15,640,418
12	March	12,804,810
13	**Total** (Sum L1:L12)	**166,567,393**

Line No.	Month	MBTUs
14	April 2018	11,053,613
15	May	12,806,726
16	June	15,479,769
17	July	20,299,371
18	August	19,387,566
19	September	17,128,278
20	October	16,867,758
21	November	14,807,040
22	December	14,345,919
23	January 2019	13,375,182
24	February	13,994,322
25	March	12,831,035
26	**Total** (Sum L14:L25)	**182,376,579**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

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

BRETT PHIPPS CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

JUNE 9, 2020

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1250

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

BRETT PHIPPS CONFIDENTIAL EXHIBIT 4

FILED UNDER SEAL

JUNE 9, 2020