ALLEN LAW OFFICES, PLLC

DWIGHT W. ALLEN
ATTORNEY

June 20, 2018

VIA ELECTRONIC FILING AND HAND DELIVERY

Ms. M. Lynn Jarvis
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Docket No. E-2, Sub 1173
Duke Energy Progress, LLC's Fuel Charge Adjustment Proceeding

Dear Ms. Jarvis:

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 Kendra A. Ward, and the testimony and exhibits of Eric Grant, Kenneth D. Church, Kelvin Henderson and Joseph A. Miller, Jr. containing the information required in NCUC Rule R8-55. I will deliver fifteen (15) paper copies of the filing to the Clerk's Office by close of business on June 21, 2018.

Information contained in Eric Grant's Exhibit 3 is confidential because it contains costs to purchase spot gas supply, and public disclosure could hinder DEP from obtaining the most cost-effective energy to meet the needs of its customers. For that reason, it is being filed under seal pursuant to N.C. Gen. Stat. § 132-1.2. This confidential document should only be shared with the Commission and Commission Staff. Parties to the docket may contact DEP regarding obtaining copies pursuant to an appropriate confidentiality agreement.

Please contact me if you have any questions.

Respectfully submitted,

/s/ Dwight W. Allen

Dwight W. Allen

Enclosures
cc: Parties of Record

1514 GLENWOOD AVENUE SUITE 200
RALEIGH, NC 27608
PHONE 919-838-0529
FAX 919-838-1529
DALLEN@THEALLENLAWOFFICES.COM

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1173

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

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 names and addresses of Applicant's attorneys are:

Dwight W. Allen
Allen Law Offices, PLLC
1514 Glenwood Avenue, Suite 200
Raleigh, North Carolina 27608
Tel: (919) 838-0529
dallen@theallenlawoffices.com

Robert W. Kaylor
Law Office of Robert W. Kaylor, P.A.
353 Six Forks Road, Suite 260
Raleigh, North Carolina 27609
Tel: (919) 828-5250
bkaylor@rwkaylorlaw.com

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

3. NCUC Rule R8-55 provides that the Commission shall schedule annual hearings pursuant to N.C. Gen. Stat. § 62-133.2 in order to review changes in the cost of fuel and fuel-related costs since the last general rate case for each utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service. Rule R8-55 schedules an annual cost of fuel and fuel-related costs adjustment hearing for DEP and requires that the Company use a test period of 12 months ended March 31. Therefore, the test period used in this Application for these proceedings is April 1, 2017 – March 31, 2018 ("test period").

4. In Docket No. E-2, Sub 1146, 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	2.179¢ per kWh
Small General Service	2.121¢ per kWh
Medium General Service	2.356¢ per kWh
Large General Service	2.417¢ per kWh
Lighting	1.657¢ per kWh

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

Residential	2.311¢ per kWh
Small General Service	2.556¢ per kWh
Medium General Service	2.477¢ per kWh
Large General Service	1.757¢ per kWh
Lighting	2.251¢ per kWh

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

Residential	0.575¢ per kWh
Small General Service	0.363¢ per kWh
Medium General Service	0.343¢ per kWh
Large General Service	1.038¢ per kWh
Lighting	0.885¢ per kWh

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

Residential	2.886¢ per kWh
Small General Service	2.919¢ per kWh
Medium General Service	2.820¢ per kWh
Large General Service	2.795¢ per kWh
Lighting	3.136¢ per kWh

The new fuel factors should become effective for service on or after December 1, 2018.

6. In this Application, DEP proposes the following rates (excluding regulatory fee) to recover a revenue deficiency related to a fuel EMF that expired and was removed from billed rates on November 30, 2017, but was inadvertently included in the calculation of the compliance rates filed effective March 16, 2018. These rates are not included in the fuel factors shown above.

Residential	0.022¢ per kWh
Small General Service	0.052¢ per kWh
Medium General Service	0.068¢ per kWh
Large General Service	0.002¢ per kWh
Lighting	(0.046)¢ per kWh

7. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Eric Grant, Joseph A. Miller, Jr., Kelvin Henderson, Kenneth D. Church, and the testimony, exhibits, and workpapers of Kendra A. Ward, which are being filed simultaneously with this Application and incorporated herein by reference.

8. 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 (90.0%) using projected sales, and based on projected nuclear capacity factors and normalized test period sales. These base fuel and fuel-related costs factors are:

	NERC Average	Normalized Sales
Residential	2.951¢ per kWh	2.896¢ per kWh
Small General Service	2.993¢ per kWh	2.873¢ per kWh
Medium General Service	2.871¢ per kWh	2.781¢ per kWh
Large General Service	2.829¢ per kWh	2.829¢ per kWh
Lighting	3.271¢ per kWh	3.198¢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	2.886¢ per kWh
Small General Service	2.919¢ per kWh
Medium General Service	2.820¢ per kWh
Large General Service	2.795¢ per kWh
Lighting	3.136¢ per kWh

Respectfully submitted this 20th day of June, 2018.

By: */s/ Dwight W. Allen*
Dwight W. Allen
Allen Law Offices, PLLC
1514 Glenwood Avenue, Suite 200
Raleigh, North Carolina 27608
Tel: (919) 838-0529
dallen@theallenlawoffices.com
North Carolina State Bar No. 5484

Robert W. Kaylor
Law Office of Robert W. Kaylor, P.A.
353 Six Forks Road, Suite 260
Raleigh, North Carolina 27609
Tel: (919) 828-5250
bkaylor@rwkaylorlaw.com
North Carolina State Bar No. 6237

ATTORNEYS FOR DUKE ENERGY PROGRESS, LLC

STATE OF NORTH CAROLINA	)	
	)	VERIFICATION
COUNTY OF MECKLENBURG	)	

Kendra A. Ward, being first duly sworn, deposes and says:

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

Kendra A. Ward

Kendra A. Ward

Sworn to and subscribed before me this the 20th day of June, 2018.

THOMAS J. REED-HALL NOTARY PUBLIC GASTON COUNTY, NC

Notary Public

My Commission expires: 7-30-2022

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1173

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF KENDRA A. WARD 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 Kendra A. Ward. 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 Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Arts degree in Political Science and Economics from the University of North Carolina at Chapel Hill and a Masters in Accounting from Appalachian State University. I am a certified public accountant licensed in the State of North Carolina. I began my career in 2004 with Cherry, Bekaert & Holland, LLP (now known as Cherry Bekaert, LLP) as a staff auditor. From 2006 until 2013 I held various financial accounting and reporting roles at Cherry, Bekaert, LLP; Wachovia Bank (now known as Wells Fargo) and The Shaw Group, Inc. (now known as CB&I). In 2013, I started at Duke Energy as Lead Accounting Analyst and held a variety of positions in the finance organization. I joined the Rates Department in 2016 as Manager, Rates and Regulatory Filings.

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

A. Yes. I submitted testimony in DEP's fuel and fuel-related cost recovery proceedings in Docket No. E-2, Sub 1146.

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 Ward Exhibits 1 through 8, along with supporting workpapers. The test period used in supplying this information and data is the period April 1, 2017 through March 31, 2018 ("test period"), and the billing period is December 1, 2018 through November 30, 2019 ("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 WARD EXHIBITS 1 THROUGH 8 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes, these exhibits were either prepared by me or at my direction and under my supervision, 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 94.1% proposed nuclear capacity factor and projected billing period megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 94.1% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting an 90.0% 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.

Page 2: Calculation of the EMF for residential customers.

Page 3: Calculation of the EMF for small general service customers.

Page 4: Calculation of the EMF for medium general service customers.

Page 5: Calculation of the EMF for large general service customers.

Page 6: Calculation of the EMF for lighting customers.

Exhibit 4: MWh Normalized Sales, Fuel Revenue, and Fuel and Fuel-Related Expense, as well as System Peak for the test period.

Exhibit 5: Nuclear Capacity Ratings.

Exhibit 6: Calculation of Fuel EMF Deficiency Rates.

Exhibit 7: March 2018 Monthly Fuel Reports.

1) March 2018 Monthly Fuel Report required by NCUC Rule R8-52.

2) March 2018 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

Exhibit 8: Proposed Fuel EMF Deficiency Rider FED-1.

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

A. Ward Exhibit 1 presents a summary of fuel and fuel-related cost factors, including the current fuel and fuel-related cost factors, the fuel and fuel-related cost factors using the NERC five-year average nuclear capacity factor using projected billing period sales, the fuel and fuel-related cost factors using the proposed capacity factor and normalized test period sales, and the proposed fuel and fuel-related cost factors. Exhibit 1 also shows the fuel EMF deficiency rates.

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

A. The Company proposes that 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 incorporate a 94.1% nuclear capacity factor as testified to by Company witness Henderson, projected fossil fuel costs as testified to by Company witness Grant, projected nuclear fuel costs as testified to by Company witness

Church, and projected reagents costs as testified to by Company witness Miller. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Ward Exhibit 1 in cents per kWh ("cents/kWh"), are:

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Proposed Fuel and Fuel Related Costs cents/kWh	2.311	2.556	2.477	1.757	2.251
EMF Increment/(Decrement) cents/kWh	0.575	0.363	0.343	1.038	0.885
EMF Interest Decrement cents/kWh	-	-	-	-	-
Net Fuel and Fuel Related Costs Factors cents/kWh	2.886	2.919	2.820	2.795	3.136

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 6.4% increase, on average, in customers' bills. The table below shows both the proposed and existing fuel and fuel-related cost factors (without regulatory fee).

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Proposed Factors cents/kWh	2.886	2.919	2.820	2.795	3.136
Current Factors cents/kWh	2.179	2.121	2.258	2.417	1.657

Q. WHAT ARE THE KEY DRIVERS IMPACTING THE PROPOSED FUEL AND FUEL-RELATED COSTS FACTOR?

A. The largest component of the increase is the collection of $224.3 million of under-collected fuel costs related to the EMF increment, in contrast to the $10.9 million of over-collected fuel costs and interest included in the existing EMF decrement.

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 optimizing the generation fleets of DEP and DEC.

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

A. Exhibit 2 is divided into three schedules. Schedule 1 sets forth the determination of the prospective fuel and fuel-related costs. The calculation uses the nuclear capacity factor of 94.1% as explained by Company witness Henderson in his testimony, and provides the forecasted MWh sales for the billing period on which system generation and costs are based. Schedule 2 also uses the proposed capacity factor of 94.1% along with normalized test period kWh generation, as prescribed by NCUC Rule R8-55(e)(3), which requires the use of the methodology adopted by the Commission in the Company's last general rate case.

The Capacity factor shown on Schedule 3 is prescribed in NCUC Rule R8-55(d)(1). The normalized five-year national weighted average NERC nuclear capacity factor is 90.0%. This capacity factor is based on the 2012 through 2016 data reported in the NERC's Generating Unit Statistical Brochure ("NERC Brochure") for comparable units. A projected billing period kWh generation was also used for Schedule 3 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 costs factors by customer class resulting from the allocation of renewable, cogeneration, and qualifying facility capacity costs by customer class on the basis of production plant as described in paragraph 26 of the Order in the Company's general rate case in Docket No. E-2, Sub 1023.

Page 3 of Exhibit 2, Schedules 1, 2, and 3 shows the allocation of system fuel costs to 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, exclusive of regulatory fee, using the uniform percentage average bill adjustment method.

Q. PLEASE SUMMARIZE THE METHOD USED TO ADJUST TEST PERIOD KWH GENERATION IN WARD EXHIBIT 2 SCHEDULES 2 AND 3.

A. The methodology used by DEP in its most recent general rate case for determining generation mix is based upon generation dispatch modeling used on Ward Exhibit 2, Schedule 1. For purposes of this filing, as a proxy for generation dispatch modeling, Ward Exhibit 2 Schedules 2 and 3 adjust the coal generation produced by the dispatch model. For example, on Exhibit 2, Schedule 2, which is based on the proposed capacity factor and normalized test period sales, DEP decreased the level of coal generation 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 to account for the decrease in nuclear generation. The decrease in nuclear generation results from assuming an 90.0% NERC nuclear capacity factor compared to the proposed 94.1% nuclear capacity factor.

Q. DID YOU DETERMINE THAT DEP'S ANNUAL INCREASE 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 2017, AS REQUIRED BY N.C. GEN. STAT. § 62-133.2(A2)?

A. The Company's analysis shows that the annual increase in the amount recoverable under the relevant sections of the statute exceeded 2.5% of DEP's gross revenues for the NC retail jurisdiction for the preceding calendar year. A large portion of the forecasted increase in costs relates to the new subsection (10) of the statute, which provides for inclusion in fuel costs of total delivered costs associated with purchases from qualifying facilities under PURPA. As a result of this exceedance, $57,234,383 of DEP's forecasted costs for purchased power for the billing period will not be included in the proposed fuel billing factors in this proceeding as shown on Ward Exhibit 2, Schedule 1, Page 3. In future fuel proceedings, the forecasted costs will be trued up to actual costs incurred. The resulting true-up amounts will be part of the evaluation of the 2.5% cap. In addition, a reduction in the forecasted purchased power was also reflected in the fuel and fuel-related costs factors based on normalized sales on Exhibit 2, Schedule 2, Page 3 and fuel and fuel-related costs factors based on the NERC five-year national weighted average nuclear capacity factor on Exhibit 2, Schedule 3, Page 3.

Q. WARD EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD (OVER)/UNDER RECOVERY BALANCE AND THE EMF RATE. HOW DID ACTUAL FUEL EXPENSES COMPARE WITH FUEL REVENUE DURING THE TEST PERIOD?

A. Ward Exhibit 3, Pages 1 through 6, demonstrates that for the test period, the Company experienced a net under-recovery of $182.5 million for the combined customer classes. When adjusted for the previously deferred under-recovery of $41.9 million, discussed later in my testimony, the total under-recovery amount requested in this proceeding is $224.3 million. The table below shows the breakdown of this total amount by customer class.

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
EMF (over)/ under Collection of Fuel - ($ million)	$ 89.8	$ 6.9	$ 37.8	$ 86.6	$ 3.2
EMF Interest Costs ($ million)	$ -	$ -	$ -	$ -	$ -

The test period (over)/under collection amount was determined each month by comparing the amount of fuel revenue collected for each class to actual fuel and fuel-related costs incurred by class. The revenue collected is based on actual monthly sales for each class. Actual fuel and fuel-related costs incurred were first allocated to NC 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 is further allocated among customer classes as follows: capacity-related purchased power costs 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 based on allocation factors determined using the uniform percentage average bill adjustment method used in the previous fuel proceeding. The under-recovered amounts above include the deferred under-recoverd balance of $41.9 million carried forward from the prior year filing, E-2, Sub 1146. The table below shows the breakdown of this amount by customer class.

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
EMF (over)/ under Collection of PY Deferred Fuel - ($ million)	$ 21.3	$ 1.0	$ -	$ 17.8	$ 1.8

Q. HAS DEP HANDLED THE DEFERRED UNDER-RECOVERED BALANCE FROM THE PRIOR YEAR FILING (E-2, SUB 1146) AS STATED IN TESTIMONY IN THAT DOCKET?

A. Yes. In my supplemental testimony in Docket E-2, Sub 1146 I stated the following: "In its 2018 fuel proceeding, DEP will follow its normal practices to compute the EMF component of its fuel rates to address any over or under collection of the fuel and fuel-related cost for the test period of the 2018 case. The deferred amount of $41.9 million, broken down by customer class, will be added into the proposed 2018 EMF amounts for each customer class and billed in the rate period of December 2018 – November 2019. DEP will also follow its normal practices to propose the appropriate fuel and fuel-related costs for the rate period of its 2018 fuel case, which will be unaffected by the deferred recovery of the $41.9 million." In this proceeding DEP is including the deferred under-recovered amounts for the residential, small general service, large general service, and lighting classes in Ward Exhibit 3, Pages 1 through 6 as part of the EMF rate.

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

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Ward Exhibit 4 sets forth 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, as used in DEP's last general rate case (Docket No. E-2, Sub 1142) and fuel and fuel-related cost recovery proceeding (Docket No. E-2, Sub 1146). 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. Ward Exhibit 4 also sets forth actual test period fuel-related revenue and fuel expense on a total Company basis and for North Carolina Retail. Finally, Ward Exhibit 4 shows the test period peak demand for the system and for North Carolina Retail customer classes.

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

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

Q. PLEASE EXPLAIN WHAT IS SHOWN ON WARD EXHIBIT 6.

A. Ward Exhibit 6 calculates the rate to recover a revenue deficiency related to a fuel EMF that expired and was removed from billed rates on November 30, 2017, but was inadvertently included in the calculation of the compliance rates filed effective March 16, 2018. The rate calculated in Ward Exhibit 6 will recover the undercollection without interest for the time period March 16, 2018 – May 31, 2018. Ward Exhibit 8 provides the Company's proposed Fuel EMF Deficiency Rider, which will remain in effect for a 12-month period expiring on and after Novmeber 30, 2019. Starting June 1, 2018, there will be corrected compliance tariffs that remove the expired, prior-year fuel EMF going forward.

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

A. Yes. As shown on Ward Exhibit 7, DEP's test year actual fuel and fuel-related costs were 2.704 cents/kWh. Key factors in DEP's ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas and coal prices; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of DEP's and DEC's respective skills in procuring, transporting, managing and blending fuels, procuring reagents, and the increased and broader purchasing ability of the combined Company, as well as the joint dispatch of DEP's and DEC's generation resources. Company witness Henderson discusses the performance of DEP's nuclear generation fleet, and Company witness Miller discusses the performance of the fossil/hydro/solar fleet, as well as the chemicals that DEP uses to reduce emissions. Company witness Grant discusses fossil fuel procurement strategies and merger fuel-related savings, and Company witness Church discusses DEP's nuclear fuel costs and procurement strategies.

Q. IN DEVELOPING THE PROPOSED FUEL AND FUEL-RELATED COST FACTORS, WERE THE FUEL COSTS ALLOCATED IN ACCORDANCE WITH N.C. GEN. STAT. § 62-133.2(A2)?

A. Yes, the costs for which statutory guidance is provided have been allocated in compliance with N.C. Gen. Stat. § 62-133.2(a2). These costs are described in subsections (4), (5), (6), (10) and (11) of N.C. Gen. Stat. § 62-133.2(a1) and the allocation methods are specified in paragraph 31 of DEP's last general rate case

Order in Docket No. E-2, Sub 1142. Capacity-related purchased power costs in subsections (5), (6) and (10) are allocated based upon the production plant allocator from the latest annual cost of service study, using the cost of service methodology approved in DEP's most recent rate case, Docket No. E-2, Sub 1142. Subsection (4) costs and non-capacity costs in subsections (6) and (10) are allocated in the same manner as all other fuel and fuel-related costs, using a uniform percentage average bill adjustment method.

Q. HOW ARE THE OTHER FUEL COSTS ALLOCATED FOR WHICH THERE IS NO SPECIFIC GUIDANCE IN N.C. GEN. STAT. § 62-133.2(A2)?

A. System costs are allocated to NC 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 setting fuel rates in this fuel proceeding. DEP proposes to use the same uniform percentage average bill adjustment methodology to adjust its fuel rates to reflect a proposed increase in fuel and fuel-related costs as it did in its 2017 fuel and fuel-related cost recovery proceeding in Docket No. E-2, Sub 1146.

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

A. Ward 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, exclusive of regulatory fee. The uniform bill percentage change of 6.4% was calculated by dividing the fuel and fuel-related cost increase of $226 million for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $3.5 billion. The cost increase of $226 million was determined by comparing the total proposed fuel rate per kWh to the total fuel rate per kWh currently being collected from customers, and multiplying the resulting increase in fuel rate per kWh by projected North Carolina retail kWh sales for the billing period. The proposed fuel rate per kWh equals the sum of: (1) the rate necessary to recover projected period fuel costs; (2) the proposed composite EMF increment/(decrement) rate; and (3) the proposed EMF decrement interest rate (as computed on Ward Exhibit 3, page 1). Ward 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 WARD EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. In each of Ward Exhibit 2, Page 3 of Schedules 1, 2, and 3, the equal percent increase for each customer class is applied to current annual revenues by customer class to determine a dollar amount of increase for each customer class. The dollar increase is divided by the projected billing period sales for each class to derive a cents/kWh increase. The current total fuel and fuel-related cost factors for each class are adjusted by the proposed cents/kWh increase or 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 (EMF components computed on Ward Exhibit

3, Page 2, 3, 4, 5, and 6) to derive the prospective rate component for each customer class. This breakdown of projected fuel and fuel-related cost factor and EMF increment/ (decrement) is shown on Ward Exhibit 2, Page 2 of Schedules 1, 2, and 3.

Q. DO THE PROPOSED RATES INCLUDE THE NET GAIN OR LOSS ON THE SALE OF BY-PRODUCTS FOR BENEFICIAL REUSE FROM THE SUTTON COAL PLANT?

A. No. All net gains or losses related to the sale of by-products for beneficial reuse from the Sutton coal plant were removed from the fuel filing in compliance with the order in DEP's general rate case, Docket E-2, Sub 1142.

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

A. Yes. The work papers supporting the calculations, adjustments, and normalizations are included with the filing in this proceeding.

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
Test Period Twelve Months Ended March 31, 2018
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

Ward 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 1146)						
1	Approved Fuel and Fuel Related Costs Factors	Input	2.179	2.121	2.356	2.417	1.657
2	EMF Increment / (Decrement)	Input	-	-	(0.084)	-	-
3	EMF Interest Decrement cents/kWh	Input	-	-	(0.014)	-	-
4	Approved Net Fuel and Fuel Related Costs Factors	Sum	2.179	2.121	2.258	2.417	1.657
	Fuel and Fuel Related Cost Factors						
5	NERC Capacity Factor of 90.0% with Projected Sales	Exh 2 Sch 3 pg 3	2.951	2.993	2.871	2.829	3.271
6	Proposed Nuclear Capacity Factor of 94.1% and Normalized Test Period Sales	Exh 2 Sch 2 pg 3	2.896	2.873	2.781	2.829	3.198
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 94.1%						
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	2.179	2.397	2.355	1.682	2.250
8	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.132	0.159	0.122	0.075	0.001
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	2.311	2.556	2.477	1.757	2.251
10	EMF Increment/(Decrement) cents/kWh	Exh 2 Sch 1 pg 2	0.575	0.363	0.343	1.038	0.885
11	EMF Interest Decrement cents/kWh	Exh 2 Sch 1 pg 2	-	-	-	-	-
12	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 pg 2	2.886	2.919	2.820	2.795	3.136
	Proposed Fuel EMF Deficiency Rider						
13	Correction of December 2016 Fuel EMF in Compliance Rates Increment / (Decrement) cents/kWh	Exh 6	0.022	0.052	0.068	0.002	(0.046)

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 94.1%
Twelve Months December 2018 - November 2019
Docket E-2, Sub 1173

Line No.	Unit	Reference	Generation (MWH)	Unit Cost (cents/KWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 3-4	29,210,311	0.6724	$	196,401,382
2	Coal	Workpaper 3 - 4	5,721,568	3.3537		191,885,039
3	Gas - CT and CC	Workpaper 3 - 4	22,506,145	2.9036		653,485,803
4	Reagents & By Products	Workpaper 12	-			14,989,402
5	Total Fossil	Sum of Lines 2 - 4	28,227,713			860,360,244
6	Hydro	Workpaper 3	606,686			
7	Net Pumped Storage		-			
8	Total Hydro	Sum of Lines 6 - 7	606,686			
9	Utility Owned Solar Generation	Workpaper 3	304,154			
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	58,348,864			1,056,761,626
11	Purchases	Workpaper 3 - 4	10,318,993			542,149,905
12	JDA Savings Shared	Workpaper 5	-			(12,766,851)
13	Total Purchases	Sum of Lines 11 - 12	10,318,993			529,383,055
14	Total Generation and Purchases	Line 10 + Line 13	68,667,857			1,586,144,681
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(4,650,587)			(105,350,249)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,883,902)			-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16			$	1,480,794,432
18	Projected System MWh Sales for Fuel Factor	Workpaper 3	62,133,368			62,133,368
19	Fuel and Fuel Related Costs cents/kWh	Line 17 /Line 18 / 10				2.383

Note: Rounding differences may occur
Adjusted to include 100% ownership of all generating resources.

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 94.1%
Twelve Months December 2018 - November 2019
Docket E-2, Sub 1173

Line No.	Description		Residential cents/KWh	General Service Small cents/KWh	General Service Medium cents/KWh	General Service Large cents/KWh	Lighting cents/KWh	Total
1	NC Projected Billing Period MWH Sales	Workpaper 7	15,956,916	1,795,996	10,351,641	9,176,034	379,219	37,659,805
	Calculation of Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power - Capacity	Workpaper 4						$ 38,515,117
3	Cogeneration Purchased Power - Capacity							-
4	Purchases from Qualifying Facilities (HB 589)	Workpaper 4						33,362,793
5	Total of Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3 + Line 4						$ 71,877,910
6	NC Portion - Jurisdictional % based on Production Plant Allocator	Input						60.52%
7	NC Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 43,500,511
8	Production Plant Allocation Factors	Input	48.581%	6.580%	28.950%	15.881%	0.008%	100.000%
9	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity allocated on Production Plant %	Line 7 * Line 8	$ 21,132,983	$ 2,862,334	$ 12,593,398	$ 6,908,316	$ 3,480	$ 43,500,511
10	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 9 / Line 1 / 10	0.132	0.159	0.122	0.075	0.001	0.116
	Summary of Total Rate by Class							
11	Fuel and Fuel Related Costs excluding Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 16 - Line 12 - Line 14 - Line 15	2.179	2.397	2.355	1.682	2.250	
12	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity cents/kWh	Line 10	0.132	0.159	0.122	0.075	0.001	
13	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 11 + Line 12	2.311	2.556	2.477	1.757	2.251	
14	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.575	0.363	0.343	1.038	0.885	
15	EMF Interest Decrement cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
16	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	2.886	2.919	2.820	2.795	3.136	

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 94.1%
Twelve Months December 2018 - November 2019
Docket E-2, Sub 1173

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 1146 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A		B		C	D	E	F	G
		Exhibit 2, Schedule 1, page 2		Workpaper 9		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	15,956,916	$	1,752,285,692	$	112,816,226	6.4%	0.707	2.179	2.886
2	Small General Service	1,795,996	$	222,700,739	$	14,337,991	6.4%	0.798	2.121	2.919
3	Medium General Service	10,351,641	$	903,433,492	$	58,165,148	6.4%	0.562	2.258	2.820
4	Large General Service	9,176,034	$	538,274,962	$	34,655,393	6.4%	0.378	2.417	2.795
5	Lighting	379,219	$	87,096,514	$	5,607,476	6.4%	1.479	1.657	3.136
6	NC Retail	37,659,805	$	3,503,791,399	$	225,582,234				

Total Proposed Composite Fuel Rate:

Line No.	Description	Source		Amount
7	Adjusted System Total Fuel Costs	Workpaper 7	$	1,481,478,720
8	System Renewable, Cogeneration and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2		71,877,910
9	Adjusted System Other Fuel Costs	Line 7 - Line 8	$	1,409,600,810
10	NC Retail Allocation % - sales at generation	Workpaper 8		60.87%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$	858,024,013
12	NC Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2		43,500,511
13	NC Retail Total Fuel Costs before 2.5% Purchase Power Test	Line 11 + Line 12	$	901,524,524
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 14	$	(57,234,383)
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$	844,290,141
16	NC Projected Billing Period MWH Sales	Line 6, col A		37,659,805
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 / 10		2.242
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		0.602
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		2.844

Total Current Composite Fuel Rate - Docket E-2 Sub 1146:

Line No.	Description	Source		Amount
21	Current composite Fuel Rate cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3		2.274
22	Current composite EMF Rate cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3		(0.025)
23	Current composite EMF Interest cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3		(0.004)
24	Total Current Composite Fuel Rate	Sum of Lines 21-23		2.245
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24		0.599
26	NC Projected Billing Period MWH Sales	Line 6, col A		37,659,805
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$	225,582,234

Note: Rounding differences may occur

Includes 100% ownership of all generating resources

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 94.1% and Normalized Test Period Sales
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

Line No.	Unit	Reference	Generation (MWH)	Unit Cost (cents/KWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 3-4	29,210,311	0.6724	$	196,401,382
2	Coal	Calculated	5,450,720	3.3537		182,801,572
3	Gas - CT and CC	Workpaper 3-4	22,506,145	2.9036		653,485,803
4	Reagents & By Products	Workpaper 4	-			14,989,402
5	Total Fossil	Sum of Lines 2 - 4	27,956,865			851,276,777
6	Hydro	Workpaper 3	606,686			
7	Net Pumped Storage		-			
8	Total Hydro	Sum of Lines 6 - 7	606,686			
9	Utility Owned Solar Generation	Workpaper 3	304,154			
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	58,078,016			1,047,678,159
11	Purchases	Workpaper 3 - 4	10,318,993			542,149,905
12	JDA Savings Shared	Workpaper 5	-			(12,766,851)
13	Total Purchases	Sum of Lines 11 - 12	10,318,993			529,383,055
14	Total Generation and Purchases	Line 10 + Line 13	68,397,009			1,577,061,214
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(4,650,587)			(105,350,249)
16	Line losses and Company use	Line 19 - Line 15 - Line 14	(1,875,431)			-
17	System Fuel Expense for Fuel Factor	Lines 14 + Line 15 + Line 16			$	1,471,710,965
18	Normalized Test Period MWh Sales for Fuel Factor	Exhibit 4	61,870,991			61,870,991
19	Fuel and Fuel Related Costs cents/kWh	Line 17 / Line 18 / 10				2.379

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 94.1% and Normalized Test Period Sales
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

Line No.	Description		Residential cents/KWh	General Service Small cents/KWh	General Service Medium cents/KWh	General Service Large cents/KWh	Lighting cents/KWh	Total
1	NC Normalized Test Period MWH Sales	Exhibit 4	15,621,843	1,891,451	11,038,646	8,346,128	361,235	37,259,304
	Calculation of Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power - Capacity	Workpaper 4						$ 38,515,117
3	Cogeneration Purchased Power - Capacity							-
4	Purchases from Qualifying Facilities (HB 589)	Workpaper 4						33,362,793
5	Total of Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3 + Line 4						$ 71,877,910
6	NC Portion - Jurisdictional % based on Production Plant Allocator	Input						60.52%
7	NC Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 43,500,511
8	Production Plant Allocation Factors	Input	48.581%	6.580%	28.950%	15.881%	0.008%	100.000%
9	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity allocated on Production Plant %	Line 7 * Line 8	$ 21,132,983	$ 2,862,334	$ 12,593,398	$ 6,908,316	$ 3,480	$ 43,500,511
10	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 9 / Line 1 / 10	0.135	0.151	0.114	0.083	0.001	0.117
	Summary of Total Rate by Class							
11	Fuel and Fuel Related Costs excluding Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 16 - Line 12 - Line 14 - Line 15	2.186	2.359	2.324	1.708	2.312	
12	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity cents/kWh	Line 10	0.135	0.151	0.114	0.083	0.001	
13	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 11 + Line 12	2.321	2.510	2.438	1.791	2.313	
14	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.575	0.363	0.343	1.038	0.885	
15	EMF Interest Decrement cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
16	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	2.896	2.873	2.781	2.829	3.198	

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 94.1% and Normalized Test Period Sales
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

Line No.	Rate Class	Normalized 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 1146 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Exhibit 2, Schedule 2, page 2	Workpaper 9	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	15,621,843	$ 1,752,285,692	$ 111,989,132	6.4%	0.717	2.179	2.896
2	Small General Service	1,891,451	$ 222,700,739	$ 14,232,875	6.4%	0.752	2.121	2.873
3	Medium General Service	11,038,646	$ 903,433,492	$ 57,738,720	6.4%	0.523	2.258	2.781
4	Large General Service	8,346,128	$ 538,274,962	$ 34,401,323	6.4%	0.412	2.417	2.829
5	Lighting	361,235	$ 87,096,514	$ 5,566,366	6.4%	1.541	1.657	3.198
6	NC Retail	37,259,304	$ 3,503,791,399	$ 223,928,416				

Total Proposed Composite Fuel Rate:

Line No.	Description	Source	Amount
7	Adjusted System Total Fuel Costs	Workpaper 7a	$ 1,472,395,253
8	System Renewable, Cogeneration and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	71,877,910
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,400,517,343
10	NC Retail Allocation % - sales at generation	Workpaper 8	60.49%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 847,172,941
12	NC Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	43,500,511
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 890,673,452
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 14a	$ (54,730,355)
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 835,943,097
16	Adjusted NC Normalized Period MWH Sales	Line 6, col A	37,259,304
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.244
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.602
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	2.846

Total Current Composite Fuel Rate - Docket E-2 Sub 1146:

Line No.	Description	Source	Amount
21	Current composite Fuel Rate cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3	2.274
22	Current composite EMF Rate cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3	(0.025)
23	Current composite EMF Interest cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3	(0.004)
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.245
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	0.601
26	Adjusted NC Normalized Period MWH Sales	Line 6, col A	37,259,304
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$ 223,928,415

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 90.0% with Projected Sales
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

Line No.	Unit	Reference	Generation (MWH)	Unit Cost (cents/KWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 2	27,943,448	0.6724	$	187,883,372
2	Coal	Calculated	6,988,431	3.3537		234,372,000
3	Gas - CT and CC	Workpaper 3 - 4	22,506,145	2.9036		653,485,803
4	Reagents & By Products	Workpaper 4	-			14,989,402
5	Total Fossil	Sum of Lines 2 - 4	29,494,576			902,847,205
6	Hydro	Workpaper 3	606,686			
7	Net Pumped Storage		-			
8	Total Hydro	Sum of Lines 6 - 7	606,686			
9	Utility Owned Solar Generation	Workpaper 3	304,154			
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	58,348,864			1,090,730,577
11	Purchases	Workpaper 3 - 4	10,318,993			542,149,905
12	JDA Savings Shared	Workpaper 5	-			(12,766,851)
13	Total Purchases	Sum of Lines 11- 12	10,318,993			529,383,055
14	Total Generation and Purchases	Line 10 + Line 13	68,667,857			1,620,113,631
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(4,650,587)			(105,350,249)
16	Line losses and Company use	Line 19 - Line 15 - Line 14	(1,883,902)			-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16			$	1,514,763,382
18	System MWh Sales for Fuel Factor	Workpaper 3	62,133,368			62,133,368
19	Fuel and Fuel Related Costs cents/kWh	Line 17 / Line 18 / 10				2.438

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 90.0% with Projected Sales
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

Ward Exhibit 2
Schedule 3

Line No.	Description			Residential cents/KWh	General Service Small cents/KWh	General Service Medium cents/KWh	General Service Large cents/KWh	Lighting cents/KWh	Total
1	NC Projected Billing Period MWH Sales	Workpaper 7		15,956,916	1,795,996	10,351,641	9,176,034	379,219	37,659,805
	Calculation of Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity Rate by Class								Amount
2	Renewable Purchased Power - Capacity	Workpaper 4							$ 38,515,117
3	Cogeneration Purchased Power - Capacity								-
4	Purchases from Qualifying Facilities (HB 589)	Workpaper 4							33,362,793
5	Total of Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3 + Line 4							$ 71,877,910
6	NC Portion - Jurisdictional % based on Production Plant Allocator	Input							60.52%
7	NC Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6							$ 43,500,511
8	Production Plant Allocation Factors	Input		48.581%	6.580%	28.950%	15.881%	0.008%	100.000%
9	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity allocated on Production Plant %	Line 7 * Line 8		$ 21,132,983	$ 2,862,334	$ 12,593,398	$ 6,908,316	$ 3,480	$ 43,500,511
10	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 9 / Line 1 / 10		0.132	0.159	0.122	0.075	0.001	0.116
	Summary of Total Rate by Class								
11	Fuel and Fuel Related Costs excluding Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 16 - Line 12 - Line 14 - Line 15		2.244	2.471	2.406	1.716	2.385	
12	Renewable, Cogeneration, and Qualifying Facilities Purchased Power - Capacity cents/kWh	Line 10		0.132	0.159	0.122	0.075	0.001	
13	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 11 + Line 12		2.376	2.630	2.528	1.791	2.386	
14	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6		0.575	0.363	0.343	1.038	0.885	
15	EMF Interest Decrement cents/kWh	Exh 3 pg 2, 3, 4, 5, 6		-	-	-	-	-	
16	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3		2.951	2.993	2.871	2.829	3.271	

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 90.0% with Projected Sales
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

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 1146 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Exhibit 2, Schedule 3, page 2	Workpaper 9	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	15,956,916	$ 1,752,285,692	$ 123,174,978	7.0%	0.772	2.179	2.951
2	Small General Service	1,795,996	$ 222,700,739	$ 15,654,501	7.0%	0.872	2.121	2.993
3	Medium General Service	10,351,641	$ 903,433,492	$ 63,505,854	7.0%	0.613	2.258	2.871
4	Large General Service	9,176,034	$ 538,274,962	$ 37,837,441	7.0%	0.412	2.417	2.829
5	Lighting	379,219	$ 87,096,514	$ 6,122,353	7.0%	1.614	1.657	3.271
6	NC Retail	37,659,805	$ 3,503,791,399	$ 246,295,127				

Total Proposed Composite Fuel Rate:

Line No.	Description	Source	Amount
7	Adjusted System Total Fuel Costs	Workpaper 7b	$ 1,515,447,671
8	System Renewable, Cogeneration and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	71,877,910
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,443,569,761
10	NC Retail Allocation % - sales at generation	Workpaper 8	60.87%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 878,700,913
12	NC Renewable, Cogeneration, and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	43,500,511
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 922,201,425
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 14	$ (57,234,383)
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 864,967,041
16	NC Projected Billing Period MWH Sales	Line 6, col A	37,659,805
17	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 /10	2.297
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.602
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	2.899

Total Current Composite Fuel Rate - Docket E-2 Sub 1146:

Line No.	Description	Source	Amount
21	Current composite Fuel Rate cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3	2.274
22	Current composite EMF Rate cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3	(0.025)
23	Current composite EMF Interest cents/kWh	Revised Ward Exhibit 2, Sch. 1, Pg 3	(0.004)
24	Total Current Composite Fuel Rate	Sum of Lines 19 - 21	2.245
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.654
26	NC Projected Billing Period MWH Sales	Line 6, col A	37,659,805
27	Increase/(Decrease) in Fuel Costs	Line 23* Line 24 * 10	$ 246,295,127

Note: Rounding differences may occur

Note: Rounding differences may occur

Duke Energy Progress, LLC.
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Twelve Months Ended March 31, 2018
Docket E-2, Sub 1173

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 2017 (Sub 1107)			2,551,836	$ 11,792,408	-	$ 11,792,408
2	May			2,882,501	1,074,362	-	1,074,362
3	June			3,143,065	14,218,550	-	14,218,550
4	July			3,603,205	12,646,832	-	12,646,832
5	August			3,552,280	15,752,665	-	15,752,665
6	September			3,365,322	2,759	-	2,759
7	October			2,985,025	797,505	-	797,505
8	November			2,690,885	3,496,224	-	3,496,224
9	December (1) (New Rates - Sub 1146)			2,903,935	19,036,979	-	19,036,979
10	January 2018			4,015,062	101,804,334	-	101,804,334
11	February			3,240,480	632,717	(9,307,627)	(8,674,910)
12	March			2,763,834	10,521,637	-	10,521,637
13	Total Test Period			37,697,429	$ 191,776,973	$ (9,307,627)	$ 182,469,346
14	Plus: Under collection deferred in E-2, Sub 1146 in 2017						41,864,753
15	Booked (Over) Under Recovery						$ 224,334,099
16	Normalized Test Period MWH Sales	Exhibit 4					37,259,304
17	Experience Modification Increment / (Decrement) cents/KWh						0.602
18	Interest						$ -
19	EMF Interest Decrement						-

Notes:
(1) Adjustment included in (over)/under recovery total
Totals may not foot due to rounding.

Duke Energy Progress, LLC.
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Twelve Months Ended March 31, 2018
Docket E-2, Sub 1173

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 2017 (Sub 1107)		2.723	1.993	954,712	$ 6,971,117		$ 6,971,117
2	May		2.353	1.993	1,050,149	3,784,634		3,784,634
3	June		2.563	1.993	1,246,475	7,105,529		7,105,529
4	July		2.226	1.993	1,572,276	3,667,492		3,667,492
5	August		2.452	2.040	1,492,578	6,158,080		6,158,080
6	September		2.163	2.040	1,342,663	1,659,263		1,659,263
7	October		2.448	2.040	1,067,867	4,357,219		4,357,219
8	November		2.438	2.040	1,003,422	3,996,127		3,996,127
9	December (1) (New Rates - Sub 1146)		2.489	2.116	1,324,401	4,933,487		4,933,487
10	January 2018		3.590	2.212	2,139,382	29,481,610		29,481,610
11	February		1.983	2.226	1,523,879	(3,697,234)	(3,557,294)	(7,254,528)
12	March		2.513	2.202	1,175,447	3,654,188		3,654,188
13	Total Test Period				15,893,252	$ 72,071,512	$ (3,557,294)	$ 68,514,218
14	Plus: Under collection deferred in E-2, Sub 1146 in 2017							21,282,684
15	Booked (Over) Under Recovery							$ 89,796,902
16	Normalized Test Period MWH Sales	Exhibit 4						15,621,843
17	Experience Modification Increment (Decrement) cents/KWh							0.575
18	Annual Interest Rate							10%
19	Monthly Interest Rate							0.83333%
20	Number of Months (October 2017 - May 2019)							20
21	Interest							$ -
22	EMF Interest Decrement							-

Notes:
(1) Adjustment included in (over)/under recovery total
Totals may not foot due to rounding.

Duke Energy Progress, LLC.
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Small General Service
Test Period Twelve Months Ended March 31, 2018
Docket E-2, Sub 1173

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 2017 (Sub 1107)	2.478	2.088	126,398	$ 492,826		$ 492,826
2	May	2.071	2.088	143,788	(24,660)		(24,660)
3	June	2.338	2.088	164,782	411,839		411,839
4	July	2.217	2.088	190,221	246,279		246,279
5	August	2.345	2.136	188,473	394,908		394,908
6	September	1.893	2.136	185,362	(448,965)		(448,965)
7	October	2.041	2.136	154,591	(145,856)		(145,856)
8	November	2.237	2.136	131,824	133,565		133,565
9	December (1) (New Rates - Sub 1146)	2.724	2.149	141,647	813,619		813,619
10	January 2018	4.259	2.166	202,795	4,243,795		4,243,795
11	February	2.059	2.169	165,238	(181,018)	(427,226)	(608,244)
12	March	2.383	2.144	139,212	332,560		332,560
13	Total Test Period			1,934,331	$ 6,268,892	$ (427,226)	$ 5,841,666
14	Plus: Under collection deferred in E-2, Sub 1146 in 2017						1,023,834
15	Booked (Over) Under Recovery						$ 6,865,500
16	Normalized Test Period MWH Sales	Exhibit 4					1,891,451
17	Experience Modification Increment (Decrement) cents/KWh						0.363
18	Annual Interest Rate						10%
19	Monthly Interest Rate						0.83333%
20	Number of Months (October 2017 - May 2019)						20
21	Interest						$ -
22	EMF Interest Decrement						-

Notes:
(1) Adjustment included in (over)/under recovery total
Totals may not foot due to rounding.

Duke Energy Progress, LLC.
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Medium General Service
Test Period Twelve Months Ended March 31, 2018
Docket E-2, Sub 1173

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 2017 (Sub 1107)		2.652	2.431	789,518	$ 1,748,388		$ 1,748,388
2	May		2.153	2.431	924,297	(2,569,638)		(2,569,638)
3	June		2.596	2.431	988,512	1,627,980		1,627,980
4	July		2.619	2.431	1,075,522	2,022,734		2,022,734
5	August		2.790	2.474	1,049,747	3,311,218		3,311,218
6	September		2.191	2.474	1,058,549	(2,994,635)		(2,994,635)
7	October		2.156	2.474	970,578	(3,085,566)		(3,085,566)
8	November		2.392	2.474	822,703	(679,388)		(679,388)
9	December (1) (New Rates - Sub 1146)		3.163	2.443	801,738	5,771,676		5,771,676
10	January 2018		5.780	2.405	967,815	32,669,134		32,669,134
11	February		2.494	2.399	869,360	827,631	(2,891,957)	(2,064,326)
12	March		2.634	2.377	806,191	2,075,998		2,075,998
13	Total Test Period				11,124,532	$ 40,725,530	$ (2,891,957)	$ 37,833,573
14	Plus: Under collection deferred in E-2, Sub 1146 in 2017							-
15	Booked (Over) Under Recovery							$ 37,833,573
16	Normalized Test Period MWH Sales	Exhibit 4						11,038,646
17	Experience Modification Increment (Decrement) cents/KWh							0.343
18	Annual Interest Rate							10%
19	Monthly Interest Rate							0.83333%
20	Number of Months (October 2017 - May 2019)							20
21	Interest							$ -
22	EMF Interest Decrement							-

Notes:
[(1)] Adjustment included in (over)/under recovery total
Totals may not foot due to rounding.

Duke Energy Progress, LLC.
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Large General Service
Test Period Twelve Months Ended March 31, 2018
Docket E-2, Sub 1173

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 2017 (Sub 1107)		2.645	2.253	652,260	$	2,555,619			$	2,555,619
2	May		2.238	2.253	732,368		(112,858)				(112,858)
3	June		2.956	2.253	712,955		5,014,712				5,014,712
4	July		3.155	2.253	734,908		6,626,518				6,626,518
5	August		3.029	2.294	791,056		5,818,694				5,818,694
6	September		2.530	2.294	748,823		1,771,340				1,771,340
7	October		2.252	2.294	761,068		(318,203)				(318,203)
8	November		2.302	2.294	703,016		58,561				58,561
9	December (1) (New Rates - Sub 1146)		3.584	2.361	607,070		7,425,005				7,425,005
10	January 2018		7.547	2.446	675,275		34,448,206				34,448,206
11	February		3.012	2.458	652,526		3,616,627		(2,403,226)		1,213,401
12	March		3.153	2.437	613,366		4,390,398				4,390,398
13	Total Test Period				8,384,692	$	71,294,620	$	(2,403,226)	$	68,891,394
14	Plus: Under collection deferred in E-2, Sub 1146 in 2017										17,750,323
15	Booked (Over) Under Recovery									$	86,641,717
16	Normalized Test Period MWH Sales	Exhibit 4									8,346,128
17	Experience Modification Increment (Decrement) cents/KWh										1.038
18	Annual Interest Rate										10%
19	Monthly Interest Rate										0.83333%
20	Number of Months (October 2017 - May 2019)										20
21	Interest									$	-
22	EMF Interest Decrement										-

Notes:
(1) Adjustment included in (over)/under recovery total
Totals may not foot due to rounding.

Duke Energy Progress, LLC.
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Lighting
Test Period Twelve Months Ended March 31, 2018
Docket E-2, Sub 1173

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 2017 (Sub 1107)		0.680	0.596	28,948	$	24,458			$	24,458
2	May		0.586	0.596	31,898		(3,116)				(3,116)
3	June		0.789	0.596	30,342		58,490				58,490
4	July		0.873	0.596	30,278		83,809				83,809
5	August		0.887	0.658	30,425		69,765				69,765
6	September		0.711	0.658	29,925		15,756				15,756
7	October		0.625	0.658	30,920		(10,089)				(10,089)
8	November		0.616	0.658	29,919		(12,641)				(12,641)
9	December (1) (New Rates - Sub 1146)		1.414	1.093	29,078		93,192				93,192
10	January 2018		4.870	1.642	29,796		961,589				961,589
11	February		1.945	1.719	29,476		66,711		(27,924)		38,787
12	March		1.918	1.687	29,618		68,493				68,493
13	Total Test Period				360,623	$	1,416,415	$	(27,924)	$	1,388,491
14	Plus: Under collection deferred in E-2, Sub 1146 in 2017										1,807,912
15	Booked (Over) Under Recovery									$	3,196,403
16	Normalized Test Period MWH Sales	Exhibit 4									361,235
17	Experience Modification Increment (Decrement) cents/KWh										0.885
18	Annual Interest Rate										10%
19	Monthly Interest Rate										0.83333%
20	Number of Months (October 2017 - May 2019)										20
21	Interest									$	-
22	EMF Interest Decrement										-

Notes:
(1) Adjustment included in (over)/under recovery total
Totals may not foot due to rounding.

Duke Energy Progress, LLC.
North Carolina Annual Fuel and Fuel Related Expense
Sales, Fuel Revenue, Fuel Expense and System Peak
Test Period Twelve Months Ended March 31, 2018
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

Ward Exhibit 4

Line No.	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina Small General Service	North Carolina Medium General Service	North Carolina Large General Service	North Carolina Lighting
1	Test Period MWH Sales	Company Records	62,453,151	37,697,429	15,893,252	1,934,331	11,124,532	8,384,692	360,623
2	Customer Growth MWH Adjustment	Workpaper 12	367,658	215,505	137,163	11,784	23,604	42,341	613
3	Weather MWH Adjustment	Workpaper 11	(949,818)	(653,630)	(408,572)	(54,664)	(109,490)	(80,904)	-
4	Total Adjusted MWH Sales	Sum Lines 1-3	61,870,991	37,259,304	15,621,843	1,891,451	11,038,646	8,346,128	361,235
5	Test Period Fuel and Fuel Related Revenue *		$ 1,478,909,275	$ 841,686,271					
6	Test Period Fuel and Fuel Related Expense *		$ 1,688,993,608	$ 1,024,155,617					
7	Test Period Unadjusted (Over)/Under Recovery	Line 5 - Line 6	$ 210,084,333	$ 182,469,346					

		Winter Coincidental Peak (CP) KW
8	Total System Peak	14,154,354
9	NC Retail	8,441,853
10	NC Residential Peak	5,330,241
11	NC Small General Service	454,283
12	NC Medium General Service	1,730,830
13	NC Large General Service	926,500

Notes:
* Total Company Fuel and Fuel Related Revenue and Fuel and Fuel Related Expense are determined based upon the fuel and fuel related cost recovery mechanisms in each of the company's jurisdictions.

Rounding differences may occur

Duke Energy Progress, LLC. **Ward Exhibit 5**
North Carolina Annual Fuel and Fuel Related Expense
Nuclear Capacity Ratings - MWs
Test Period Twelve Months Ended March 31, 2018
Billing Period December 1, 2018 - November 30, 2019
Docket E-2, Sub 1173

Unit	Rate Case Docket E-2, Sub 1142	Fuel Docket E-2, Sub 1146	Proposed Capacity Rating MW
Brunswick 1	938	938	938
Brunswick 2	932	932	932
Harris 1	928	928	932
Robinson 2	741	741	741
Total Company	3,539	3,539	3,543

Duke Energy Progress, LLC. **Ward Exhibit 6**

North Carolina Annual Fuel and Fuel Related Expense

Calculation of Fuel EMF Deficiency Rates

Docket E-2, Sub 1173

Rate Class	Residential	Small General Service	Medium General Service	Large General Service	Lighting
March 2018 kWh Sales[1]	154,521,470	17,222,832	89,368,710	38,221,917	3,145,188
April 2018 kWh Sales[1]	978,887,275	120,138,944	708,597,097	450,174,978	26,072,668
May 2018 kWh Sales[1]	1,016,144,646	136,806,000	871,434,718	689,302,944	29,670,105
Total kWh Sales	2,149,553,391	274,167,776	1,669,400,525	1,177,699,839	58,887,961
December 2016 EMF Rate (cents/kWh)[2]	(0.160)	(0.359)	(0.448)	(0.016)	0.280
Revenue Impact	(3,439,285)	(984,262)	(7,478,914)	(188,432)	164,886
Normalized Test Period MWH Sales	15,621,843	1,891,451	11,038,646	8,346,128	361,235
Increment (Decrement) cents/KWh	0.022	0.052	0.068	0.002	(0.046)

[1] Billed Sales under the Docket No. E-2, Sub 1142 compliance rates effective March 16, 2018, per company records

[2] EMF Rate is per Annual Billing Adjustments Rider BA-12 and includes the NC Regulatory Fee

Duke Energy Progress, LLC. Ward Exhibit 7
North Carolina Annual Fuel and Fuel Related Expense
Monthly Fuel and Baseload Report for March 2016
Test Period Twelve Months Ended March 31, 2018
Docket E-2, Sub 1173

Monthly Fuel Filing and Baseload Report Cover Sheet

Exhibit 7
Schedule 1

Duke Energy Progress
Summary of Monthly Fuel Report

Docket No. E-2, Sub 1164

Line No.	Fuel Expenses:		March 2018		12 Months Ended March 2018
1	Total Fuel and Fuel-Related Costs	$	123,514,039	$	1,688,993,608
	MWH sales:				
2	Total System Sales		4,906,209		67,937,557
3	Less intersystem sales		252,246		5,484,405
4	Total sales less intersystem sales		4,653,963		62,453,152
5	Total fuel and fuel-related costs (¢/KWH) (Line 1/Line 4)		2.654		2.704
6	Current fuel & fuel-related cost component (¢/KWH) (per Schedule 4, Line 5a Total)		2.297		
	Generation Mix (MWH):				
	Fossil (By Primary Fuel Type):				
7	Coal		459,748		9,240,778
8	Oil		6,725		376,658
9	Natural Gas - Combustion Turbine		370,780		2,089,636
10	Natural Gas - Combined Cycle		1,672,122		20,467,065
11	Total Fossil		2,509,375		32,174,137
12	Nuclear		2,033,784		29,666,537
13	Hydro - Conventional		73,923		587,221
14	Solar Distributed Generation		21,477		247,821
15	Total MWH generation		4,638,559		62,675,716

Notes: Detail amounts may not add to totals shown due to rounding.
Line 1 excludes April through June Sutton beneficial reuse.

Duke Energy Progress
Details of Fuel and Fuel-Related Costs

Docket No. E-2, Sub 1164

Description	March 2018	12 Months Ended March 2018
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0501110 coal consumed - steam	$ 16,172,215	$ 312,848,340
0501310 fuel oil consumed - steam	973,543	10,155,828
Total Steam Generation - Account 501	17,145,758	323,004,168
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	13,884,551	203,484,583
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	9,190,716	91,290,352
0547000 natural gas consumed - Combined Cycle	52,622,346	700,670,360
0547200 fuel oil consumed	345,916	66,682,534
Total Other Generation - Account 547	62,158,978	858,643,246
Reagents		
Catalyst Depreciation	364,468	6,936,927
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	787,583	14,832,880
Total Reagents	1,152,051	21,769,806
By-products		
Net proceeds from sale of by-products	1,213,568	4,675,972
Total By-products	1,213,568	4,675,972
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	95,554,906	1,411,577,774
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (PURPA)	2,458,565	14,220,929
Capacity component of purchased power (renewables)	1,053,053	40,664,605
Fuel and fuel-related component of purchased power	32,585,896	395,666,483
Total Purchased Power and Net Interchange - Account 555	36,097,515	450,552,017
Less fuel and fuel-related costs recovered through intersystem sales - Account 447	8,138,382	173,136,183
Total Fuel and Fuel-Related Costs	$ 123,514,039	$ 1,688,993,608

Notes: Detail amounts may not add to totals shown due to rounding.
Net proceeds from sale of by-products excludes April through June Sutton beneficial reuse.

Exhibit 7
Schedule 3, Purchases
Page 1 of 4

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

MARCH 2018

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Broad River Energy, LLC.	$ 6,036,509	$ 1,085,194	108,490	$ 4,035,731	$ 915,584	
City of Fayetteville	892,645	714,350	3,084	81,645	96,650	
DE Carolinas - Native Load Transfer	6,465,830	-	190,808	5,080,298	1,383,982	$ 1,550
DE Carolinas - Native Load Transfer Benefit	371,126	-	-	371,126	-	
DE Carolinas - Fees	802,539	-	-	-	802,539	
Haywood EMC	29,050	29,050	-	-	-	
NCEMC	4,546,722	2,712,743	45,543	1,833,979	-	
PJM Interconnection, LLC.	(1,015)	-	-	-	(1,015)	
Southern Company Services	4,065,103	787,332	109,089	2,696,096	581,675	
	$ 23,208,509	**$ 5,328,669**	**457,014**	**$ 14,098,875**	**$ 3,779,415**	**$ 1,550**
Renewable Energy						
REPS	$ 10,551,470	-	162,520	-	$ 10,551,470	-
DERP Qualifying Facilities	48,912	-	966	-	48,912	-
	$ 10,600,382	**$ -**	**163,486**	**$ -**	**$ 10,600,382**	**$ -**
HB589 PURPA Purchases						
Qualifying Facilities	$ 7,578,107	-	121,964		$ 7,578,107	-
	$ 7,578,107	**$ -**	**121,964**	**$ -**	**$ 7,578,107**	**$ -**
Non-dispatchable						
Energy Imbalance	$ 44,297		1,234	$ 38,572		$ 5,725
Generation Imbalance	3,547		114	2,164		1,383
	$ 47,844	**$ -**	**1,348**	**$ 40,736**	**$ -**	**$ 7,108**
Total Purchased Power	**$ 41,434,842**	**$ 5,328,669**	**743,812**	**$ 14,139,611**	**$ 21,957,904**	**$ 8,658**

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

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

MARCH 2018

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Market Based:					
NCEMC Purchase Power Agreement	$ 945,265	$ 652,500	9,547	$ 332,996	$ (40,231)
PJM Interconnection, LLC.	11,680	-	238	7,837	3,843
Other:					
DE Carolinas - Native Load Transfer Benefit	1,423,414	-	-	1,423,414	-
DE Carolinas - Native Load Transfer	6,760,693	-	242,448	6,374,135	386,558
Generation Imbalance	(2)	-	13	-	(2)
Total Intersystem Sales	**$ 9,141,050**	**$ 652,500**	**252,246**	**$ 8,138,382**	**$ 350,168**

* 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 2018

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Broad River Energy, LLC.	$ 81,621,192	$ 44,488,519	537,408	$ 29,885,545	$ 7,247,128	
City of Fayetteville	21,987,506	12,748,400	53,539	8,438,800	800,306	
DE Carolinas - Native Load Transfer	62,537,002	-	1,514,709	37,838,000	23,697,832	$ 1,001,170
DE Carolinas - Native Load Transfer Benefit	4,360,824	-	-	4,360,824	-	
DE Carolinas - Fees	1,284,829	-	-	-	1,284,829	
Haywood EMC	355,800	355,800	-	-	-	
NCEMC	54,875,007	36,519,963	288,781	18,355,044	-	
PJM Interconnection, LLC.	3,464,720	-	50,256	2,304,428	1,160,292	
Southern Company Services	49,722,669	13,271,548	1,104,378	30,812,493	5,638,628	
	$ 280,209,549	**$ 107,384,230**	**3,549,071**	**$ 131,995,134**	**$ 39,829,015**	**$ 1,001,170**
Renewable Energy						
REPS	$ 222,130,053	-	3,255,337	$ -	$ 219,573,488	$ 2,556,565
DERP Net Metering Excess Generation	2,673	$ 463	62	-	-	2,210
DERP Qualifying Facilities	71,592	-	1,432	-	71,592	-
	$ 222,204,318	**$ 463**	**3,256,831**	**$ -**	**$ 219,645,080**	**$ 2,558,775**
HB589 PURPA Purchases						
Qualifying Facilities	$ 58,574,133	-	927,268		$ 58,574,133	-
	$ 58,574,133	**$ -**	**927,268**	**$ -**	**$ 58,574,133**	**$ -**
Non-dispatchable						
Virginia Electric and Power Company - Emergency	$ 265,573	-	890	$ 161,999		$ 103,574
Cargill-Alligant, LLC.	72,000	-	1,500	43,920		28,080
Haywood EMC	12,962	$ 12,962	-	-		-
Smurfit Stone Container Corp	106,362	-	3,324	98,072		8,290
Energy Imbalance	202,049	-	3,302	176,560		25,489
Generation Imbalance	46,940	-	1,628	28,105		18,835
Qualifying Facilities - Pre HB589	30,373,016	7,215,071	431,674	-		23,157,945
	$ 31,078,902	**$ 7,228,033**	**442,318**	**$ 508,656**	**$ -**	**$ 23,342,213**
Total Purchased Power	**$ 592,066,902**	**$ 114,612,726**	**8,175,488**	**$ 132,503,790**	**$ 318,048,228**	**$ 26,902,158**

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

Jun 20 2018 OFFICIAL COPY

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

Twelve Months Ended
MARCH 2018

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
SC Electric & Gas - Emergency	$ 57,649	-	1,593	$ 49,290	$ 8,359
SC Public Service Authority - Emergency	116,020	$ 64,000	400	43,053	8,967
Market Based:					
NCEMC Purchase Power Agreement	12,683,004	7,830,000	124,183	7,934,954	(3,081,950)
PJM Interconnection, LLC.	3,829,604	-	53,827	1,949,091	1,880,513
Other:					
DE Carolinas - Native Load Transfer Benefit	15,515,060	-	-	15,515,060	-
DE Carolinas - Native Load Transfer	153,524,666	-	5,304,271	147,644,735	5,879,931
Generation Imbalance	(863)	-	131	-	(863)
Total Intersystem Sales	**$ 185,725,140**	**$ 7,894,000**	**5,484,405**	**$ 173,136,183**	**$ 4,694,957**

* Sales for resale other than native load priority.

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

Exhibit 7
Schedule 4

Duke Energy Progress
(Over) / Under Recovery of Fuel Costs
March 2018

Line No.			Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total
1	1a. System Retail kWh sales	Input						4,653,962,859
	1b. System kWh Sales at generation	Input						4,817,946,985
2	2a. DERP Net Metered kWh generation	Input						1,044,569
	2b. Line loss percentage from Cost of Service	Input Annually						4.159%
	2c. DERP Net Metered kWh at generation	L2a * (1 + 2b)						1,088,013
3	Adjusted System kWh sales	L1b + L2c						4,819,034,998
4	4a. N.C. Retail kWh sales	Input	1,175,447,120	139,211,843	806,191,454	613,365,604	29,618,298	2,763,834,319
	4b. Line loss percentage from Cost of Service	Input Annually	4.807%	4.806%	4.598%	3.402%	4.804%	
	4c. NC kWh Sales at generation	4a * (1+4b)	1,231,950,863	145,902,364	843,260,137	634,232,302	31,041,161	2,886,386,827
	4d. NC allocation % by customer class	Calculated	42.681%	5.055%	29.215%	21.973%	1.075%	
	4e. NC retail % of actual system total	L4c NC Total / L1b Total System						59.909%
	4f. NC retail % of adjusted system total	L4c NC Total / L3 Total System						59.896%
5	Approved fuel and fuel-related rates (¢/kWh)							
	5a Billed rates by class (¢/kWh)	Input Annually	2.179	2.121	2.356	2.417	1.657	
	5b Purchased Power in Base Rates (¢/kWh) - Note 2	Input	0.023	0.023	0.021	0.020	0.030	
	5c Total billed rates by class (¢/kWh)	L5a + L5b	2.202	2.144	2.377	2.437	1.687	2.297
	5d Billed fuel expense	L4a * L5c / 100	$25,879,743	$2,984,747	$19,162,391	$14,946,137	$499,675	$63,472,693
6	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)							
	6a Docket E-2, Sub 1146 allocation factor	Input Annually	39.67%	4.43%	28.69%	26.42%	0.79%	100.00%
	6b System incurred expense	Input						$120,035,875
	6c NC incurred expense by class	L4f * L6a * L6b	$28,521,416	$3,185,023	$20,627,160	$18,995,105	$567,984	$71,896,688
	6d NC Incurred base fuel rates (¢/kWh)	L6c / L4a * 100	2.42643	2.28790	2.55859	3.09687	1.91768	2.60134
7	Incurred renewable purchased power capacity rates (¢/kWh)							
	7a NC retail production plant %	Input Annually						59.73%
	7b Production plant allocation factors	Input Annually	48.271%	6.307%	29.139%	16.275%	0.009%	100.00%
	7c System incurred expense	Input						$3,511,619
	7d NC incurred renewable capacity expense	L7a* L7b* L7c	$1,012,520	$132,285	$611,224	$341,381	$185	$2,097,595
	7e NC incurred rates by class	L7d / L4a * 100	0.08614	0.09502	0.07582	0.05566	0.00062	0.07589
8	Total incurred rates by class (¢/kWh)	L6h + 7e	2.5126	2.3829	2.6344	3.1525	1.9183	
9	Difference in ¢/kWh (incurred - billed)	L5c - L8	0.31088	0.23889	0.2575068	0.71579	0.23125	
10	(Over) / under recovery [See footnote]	L9 * L4a / 100	$3,654,188	$332,560	$2,075,998	$4,390,398	$68,493	$10,521,637
11	Prior period adjustments	Input						0
12	Total (over) / under recovery [See footnote]	L10 + L11	$3,654,188	$332,560	$2,075,998	$4,390,398	$68,493	$10,521,637
13	Total System Incurred Expenses							$123,547,494
14	Less: Jurisdictional allocation adjustment	Input						33,455
15	Total Fuel and Fuel-related Costs per Schedule 2							$123,514,039
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 2017	$ 11,792,408	$ 6,971,117	$ 492,826	$ 1,748,388	$ 2,555,619	$ 24,458	$ 11,792,408
	May	12,866,770	3,784,634	(24,660)	(2,569,638)	(112,858)	(3,116)	1,074,362
	June	27,085,320	7,105,529	411,839	1,627,980	5,014,712	58,490	14,218,550
	July	39,732,152	3,667,492	246,279	2,022,734	6,626,518	83,809	12,646,832
	August	55,484,817	6,158,080	394,908	3,311,218	5,818,694	69,765	15,752,665
	September	55,487,576	1,659,263	(448,965)	(2,994,635)	1,771,340	15,756	2,759
	October	56,285,081	4,357,219	(145,856)	(3,085,566)	(318,203)	(10,089)	797,505
	November	59,781,305	3,996,127	133,565	(679,388)	58,561	(12,641)	3,496,224
	December	78,818,284	4,933,487	813,619	5,771,676	7,425,005	93,192	19,036,979
	January 2018	180,622,618	29,481,610	4,243,795	32,669,134	34,448,206	961,589	101,804,334
_/1	February	171,947,708	(7,254,528)	(608,244)	(2,064,326)	1,213,401	38,787	(8,674,910)
	March	$ 182,469,345	3,654,188	332,560	2,075,998	4,390,398	68,493	10,521,637
	Total		$ 68,514,218	$ 5,841,666	$ 37,833,575	$ 68,891,393	$ 1,388,493	$ 182,469,345

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.

_/2 Purchased power in base rates only represents the first 15 days of March per Docket E-2, Sub 1142. Purchased power will be in fuel rates going forward, beginning March 16, 2018.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2018

Description	Weatherspoon CT	Lee CC	Sutton CC/CT	Robinson Nuclear	Asheville Steam	Asheville CT	Roxboro Steam	Mayo Steam
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	$5,605,018	-	$14,127,492	$1,088,158
Oil	959	-	-	-	(6,330)	-	489,297	276,024
Gas - CC	-	17,976,147	13,680,108	-	-	-	-	-
Gas - CT	23	-	976,936	-	-	1,147,519	-	-
Total	982	$17,976,147	$14,657,044	-	$5,598,688	$1,147,519	$14,616,789	$1,364,182
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	326.95	-	307.92	370.62
Oil	-	-	-	-	-	-	1,571.74	1,561.66
Gas - CC	-	390.01	453.27	-	-	-	-	-
Gas - CT	-	-	410.45	-	-	386.40	-	-
Weighted Average	-	390.01	450.14	-	326.58	386.40	316.43	[illegible]
Cost of Fuel Burned ($)								
Coal	-	-	-	-	$3,188,731	-	$10,039,468	$2,944,016
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	45,478	-	-	-	135,010	247,399	527,192	311,342
Gas - CC	-	17,976,147	13,680,108	-	-	-	-	-
Gas - CT	23	-	976,936	-	-	1,147,519	-	-
Nuclear	-	-	-	4,106,946	-	-	-	-
Total	$45,501	$17,976,147	$14,657,044	$4,106,946	$3,323,741	$1,394,918	$10,566,660	3,255,358
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	317.17	-	319.18	330.77
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	1,583.50	-	-	-	1,648.47	1,648.56	1,537.90	1,511.88
Gas - CC	-	390.01	453.27	-	-	-	-	-
Gas - CT	-	-	410.45	-	-	386.40	-	-
Nuclear	-	-	-	69.31	-	-	-	-
Weighted Average	1,584.30	390.01	450.14	69.31	327.93	447.11	332.32	357.48
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	3.82	-	3.27	4.25
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	47.37	-	-	-	19.98	20.41	15.88	19.44
Gas - CC	-	2.83	3.24	-	-	-	-	-
Gas - CT	-	-	3.88	-	-	4.46	-	-
Nuclear	-	-	-	0.70	-	-	-	-
Weighted Average	47.40	2.83	3.28	0.70	3.95	5.18	3.41	4.60
Burned MBTU's								
Coal	-	-	-	-	1,005,375	-	3,145,392	890,057
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	2,872	-	-	-	8,190	15,007	34,280	20,593
Gas - CC	-	4,609,163	3,018,123	-	-	-	-	-
Gas - CT	-	-	238,016	-	-	296,978	-	-
Nuclear	-	-	-	5,925,058	-	-	-	-
Total	2,872	4,609,163	3,256,139	5,925,058	1,013,565	311,985	3,179,672	910,650
Net Generation (mWh)								
Coal	-	-	-	-	83,505	-	307,006	69,237
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	96	-	-	-	676	1,212	3,319	1,602
Gas - CC	-	635,445	421,670	-	-	-	-	-
Gas - CT	-	-	25,148	-	-	25,734	-	-
Nuclear	-	-	-	590,430	-	-	-	-
Hydro (Total System)								
Solar (Total System)								
Total	96	635,445	446,818	590,430	84,181	26,946	310,325	70,839
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	-	-	$41,853	$10,301
Limestone	-	-	-	-	104,520	-	313,013	79,074
Re-emission Chemical	-	-	-	-	-	-	-	-
Sorbents	-	-	-	-	8,110	-	98,233	28,204
Urea	-	-	-	-	83,163	-	-	-
Total	-	-	-	-	$195,792	-	$453,100	$117,579

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit, terminal and tolling agreement activity.
Cents/MBTU and cents/kWh are not computed when costs and/or net generation is negative.
Lee and Wayne oil burn is associated with inventory consumption shown on Schedule 6 for Wayne.
Re-emission chemical reagent expense is not recoverable in NC.

Exhibit 7
Schedule 5
Page 2 of 2

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2018

Description	Brunswick Nuclear	Blewett CT	Wayne County CT	Darlington CT	Smith Energy Complex CC/CT	Harris Nuclear	Current Month	Total 12 ME March 2018
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	-	-	$20,820,668	$273,56[illegible]18
Oil	-	-	(29,034)	(37,281)	17,990	-	711,625	77,82[illegible]14
Gas - CC	-	-	-	-	20,966,091	-	52,622,346	700,670,360
Gas - CT	-	-	98,133	70,901	6,897,204	-	9,190,716	91,290,352
Total	-	-	$69,099	$33,620	$27,881,285	-	$83,345,355	$1,143,35[illegible]44
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	-	-	315.65	318.72
Oil	-	-	1,036.56	11,128.66	1,025.59	-	1,500.56	1,692.60
Gas - CC	-	-	-	-	498.11	-	444.58	479.96
Gas - CT	-	-	350.25	367.27	193.33	-	221.47	390.33
Weighted Average	-	-	274.02	177.23	358.44	-	368.30	4[illegible].09
Cost of Fuel Burned ($)								
Coal	-	-	-	-	-	-	$16,172,215	$312,848,340
Oil - CC	-	-	-	-	156	-	156	5[illegible]66
Oil - Steam/CT	-	25,506	9,859	17,517	-	-	1,319,303	76,778,393
Gas - CC	-	-	-	-	20,966,091	-	52,622,346	700,670,360
Gas - CT	-	-	98,133	70,901	6,897,204	-	9,190,716	91,290,352
Nuclear	4,881,884	-	-	-	-	4,895,721	13,884,551	203,484,[illegible]83
Total	$4,881,884	$25,506	$107,992	$88,418	$27,863,451	$4,895,721	$93,189,287	$1,385,131,994
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	-	-	320.82	315.35
Oil - CC	-	-	-	-	1,733.33	-	1,733.33	1,842.03
Oil - Steam/CT	-	1,667.07	1,760.54	1,762.27	-	-	1,570.11	1,650.30
Gas - CC	-	-	-	-	498.11	-	444.58	479.96
Gas - CT	-	-	350.25	367.27	193.33	-	221.47	390.33
Nuclear	62.81	-	-	-	-	65.45	65.56	65.07
Weighted Average	62.81	1,667.07	377.89	435.58	358.29	65.45	220.37	236.38
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	-	-	3.52	3.39
Oil - CC	-	-	-	-	15.60	-	15.60	20.32
Oil - Steam/CT	-	94.47	-	-	-	-	19.62	20.40
Gas - CC	-	-	-	-	3.41	-	3.15	3.42
Gas - CT	-	-	5.58	5.90	2.18	-	2.48	4.37
Nuclear	0.67	-	-	-	-	0.68	0.68	0.69
Weighted Average	0.67	94.47	6.42	8.26	2.99	0.68	2.01	2.21
Burned MBTU's								
Coal	-	-	-	-	-	-	5,040,824	99,206,526
Oil - CC	-	-	-	-	9	-	9	3,255
Oil - Steam/CT	-	1,530	560	994	-	-	84,026	4,652,392
Gas - CC	-	-	-	-	4,209,128	-	11,836,414	145,983,948
Gas - CT	-	-	28,018	19,305	3,567,622	-	4,149,939	23,387,875
Nuclear	7,772,130	-	-	-	-	7,480,052	21,177,240	312,735,532
Total	7,772,130	1,530	28,578	20,299	7,776,759	7,480,052	42,288,452	585,969,528
Net Generation (mWh)								
Coal	-	-	-	-	-	-	459,748	9,240,778
Oil - CC	-	-	-	-	1	-	1	295
Oil - Steam/CT	-	27	(77)	(131)	-	-	6,724	376,363
Gas - CC	-	-	-	-	615,007	-	1,672,122	20,467,065
Gas - CT	-	-	1,760	1,202	316,936	-	370,780	2,089,636
Nuclear	727,984	-	-	-	-	715,370	2,033,784	29,666,537
Hydro (Total System)							73,923	587,221
Solar (Total System)							21,477	247,821
Total	727,984	27	1,683	1,071	931,944	715,370	4,638,559	62,675,716
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	$21,113	-	$73,267	$1,860,168
Limestone	-	-	-	-	-	-	496,607	9,348,300
Re-emission Chemical	-	-	-	-	-	-	-	226,743
Sorbents	-	-	-	-	-	-	134,546	2,624,356
Urea	-	-	-	-	-	-	83,163	1,000,055
Total	-	-	-	-	$21,113	-	$787,583	$15,059,623

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2018

Description	Weatherspoon	Lee	Sutton	Robinson	Asheville
Coal Data:					
Beginning balance	-	-	-	-	99,694
Tons received during period	-	-	-	-	69,160
Inventory adjustments	-	-	-	-	-
Tons burned during period	-	-	-	-	40,636
Ending balance	-	-	-	-	128,218
MBTUs per ton burned	-	-	-	-	24.74
Cost of ending inventory ($/ton)	-	-	-	-	78.39
Oil Data:					
Beginning balance	689,629	-	2,638,405	78,040	2,971,224
Gallons received during period	-	-	-	-	-
Miscellaneous use and adjustments	-	-	-	-	(4,205)
Gallons burned during period	20,520	-	-	-	168,735
Ending balance	669,109	-	2,638,405	78,040	2,798,284
Cost of ending inventory ($/gal)	2.22	-	2.80	2.49	2.27
Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	4,483,691	3,168,771	-	289,172
MCF burned during period	-	4,483,691	3,168,771	-	289,172
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	-	-	-	-	18,351
Tons received during period	-	-	-	-	735
Inventory adjustments	-	-	-	-	-
Tons consumed during period	-	-	-	-	2,049
Ending balance	-	-	-	-	17,037
Cost of ending inventory ($/ton)	-	-	-	-	48.86

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

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Repor
March 2018

Description	Roxboro	Mayo	Brunswick	Blewett	Wayne County
Coal Data:					
Beginning balance	981,749	305,174	-	-	-
Tons received during period	180,080	11,613	-	-	-
Inventory adjustments	-	-	-	-	-
Tons burned during period	124,633	36,007	-	-	-
Ending balance	1,037,196	280,780	-	-	-
MBTUs per ton burned	25.24	24.72	-	-	-
Cost of ending inventory ($/ton)	80.52	81.76	-	-	-
Oil Data:					
Beginning balance	381,833	294,896	174,304	715,134	11,661,259
Gallons received during period	225,587	128,081	-	-	(20,294)
Miscellaneous use and adjustments	(7,513)	(805)	-	-	-
Gallons burned during period	249,527	149,605	3,130	10,886	4,069
Ending balance	350,380	272,567	171,174	704,248	11,636,896
Cost of ending inventory ($/gal)	2.11	2.08	2.49	2.34	2.42
Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	-	-	-	27,271
MCF burned during period	-	-	-	-	27,271
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	87,881	25,621	-	-	-
Tons received during period	7,548	75	-	-	-
Inventory adjustments	-	-	-	-	-
Tons consumed during period	8,613	1,962	-	-	-
Ending balance	86,816	23,734	-	-	-
Cost of ending inventory ($/ton)	33.63	37.05	-	-	-

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Repor
March 2018

Description	Darlington	Smith Energy Complex	Harris	Current Month	Total 12 ME March 2018
Coal Data:					
Beginning balance	-	-	-	1,386,617	1,932,778
Tons received during period	-	-	-	260,853	3,384,739
Inventory adjustments	-	-	-	-	24,990
Tons burned during period	-	-	-	201,276	3,896,313
Ending balance	-	-	-	1,446,194	1,446,194
MBTUs per ton burned	-	-	-	25.04	25.46
Cost of ending inventory ($/ton)	-	-	-	80.58	80.58
Oil Data:					
Beginning balance	10,294,337	8,272,744	267,363	38,439,168	38,887,412
Gallons received during period	(2,428)	12,711	-	343,657	33,319,878
Miscellaneous use and adjustments	-	-	-	(12,523)	(180,760)
Gallons burned during period	7,211	67	-	613,750	33,869,978
Ending balance	10,284,698	8,285,388	267,363	38,156,552	38,156,552
Cost of ending inventory ($/gal)	2.43	2.33	2.49	2.41	2.41
Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	18,778	7,566,012	-	15,553,695	163,717,123
MCF burned during period	18,778	7,566,012	-	15,553,695	163,717,123
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	-	-	-	131,853	124,498
Tons received during period	-	-	-	8,358	225,395
Inventory adjustments	-	-	-	-	14,691
Tons consumed during period	-	-	-	12,624	236,997
Ending balance	-	-	-	127,587	127,587
Cost of ending inventory ($/ton)	-	-	-	36.30	36.30

Exhibit 7
Schedule 7

DUKE ENERGY PROGRESS

ANALYSIS OF COAL PURCHASED

MARCH 2018

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ASHEVILLE	SPOT	326	$ 15,315	$ 46.92
	CONTRACT	68,834	5,486,599	79.71
	ADJUSTMENTS	-	103,104	-
	TOTAL	69,160	5,605,018	81.04
MAYO	SPOT	-	-	-
	CONTRACT	11,613	863,867	74.39
	ADJUSTMENTS	-	224,291	-
	TOTAL	11,613	1,088,158	93.70
ROXBORO	SPOT	-	-	-
	CONTRACT	180,080	13,577,032	75.39
	ADJUSTMENTS	-	550,460	-
	TOTAL	180,080	14,127,492	78.45
ALL PLANTS	SPOT	326	15,315	46.92
	CONTRACT	260,527	19,927,498	76.49
	ADJUSTMENTS	-	877,855	-
	TOTAL	260,853	$ 20,820,668	$ 79.82

Exhibit 7
Schedule 8

DUKE ENERGY PROGRESS

ANALYSIS OF COAL QUALITY RECEIVED

MARCH 2018

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
ASHEVILLE	7.09	10.31	12,394	1.73
MAYO	7.06	8.49	12,642	3.27
ROXBORO	6.49	8.40	12,739	2.54

DUKE ENERGY PROGRESS

ANALYSIS OF OIL PURCHASED

MARCH 2018

	DARLINGTON	MAYO	ROXBORO
VENDOR	Indigo, Hightowers Petroleun Co. and Huguenot Fuels	Greensboro Tank Farm	Greensboro Tank Farm
SPOT/CONTRACT	Spot	Contract	Contract
SULFUR CONTENT %	0	0	0
GALLONS RECEIVED	(2,428)	128,081	225,587
TOTAL DELIVERED COST	$ (37,281)	$ 276,024	$ 489,297
DELIVERED COST/GALLON	$ 15.35	$ 2.16	$ 2.17
BTU/GALLON	138,000	138,000	138,000

	SMITH ENERGY COMPLEX	SMITH ENERGY COMPLEX	WAYNE
VENDOR	Hightowers Petroleun Co., Petroleum Traders, Potter Oil and Tire	Petroleum Traders	Hightowers Petroleun Co., Indigo and Potter Oil and Tire
SPOT/CONTRACT	Spot	Contract	Spot
SULFUR CONTENT %	0	0	0
GALLONS RECEIVED	4,684	8,027	(20,294)
TOTAL DELIVERED COST	$ 2,262	$ 15,728	$ (29,034)
DELIVERED COST/GALLON	$ 0.48	$ 1.96	$ 1.43
BTU/GALLON	138,000	138,000	138,000

Notes:
Federal environmental fee reversals for January and February for the Asheville station totaling $(6,330) are excluded.
A price adjustment and federal environmental fee reversals for the Weatherspoon station, which net to $959, are also excluded.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2017 - March, 2018
Nuclear Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Brunswick 1	7,408,780	938	90.17	90.34
Brunswick 2	7,573,495	932	92.76	93.12
Harris 1	8,077,994	929	99.26	96.70
Robinson 2	6,606,268	741	101.77	97.65

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2017 through March, 2018
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Lee Energy Complex	1A	1,484,954	224	75.85	83.02
Lee Energy Complex	1B	1,453,699	223	74.34	83.28
Lee Energy Complex	1C	1,517,702	224	77.27	84.18
Lee Energy Complex	ST1	2,885,224	379	86.90	94.61
Lee Energy Complex	Block Total	7,341,579	1,050	79.82	87.54
Richmond County CC	7	1,219,345	189	73.65	80.37
Richmond County CC	8	1,203,968	189	72.72	79.64
Richmond County CC	ST4	1,374,680	175	89.67	88.05
Richmond County CC	9	1,413,543	215	75.23	79.94
Richmond County CC	10	1,437,289	215	76.49	81.41
Richmond County CC	ST5	1,903,723	248	87.63	91.01
Richmond County CC	Block Total	8,552,548	1,230	79.38	83.61
Sutton Energy Complex	1A	1,400,211	225	71.12	79.68
Sutton Energy Complex	1B	1,452,443	225	73.77	81.77
Sutton Energy Complex	ST1	1,720,578	268	73.29	91.08
Sutton Energy Complex	Block Total	4,573,232	718	72.76	84.59

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, 2017 through March, 2018

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Mayo 1	1,441,969	746	22.07	86.01
Roxboro 2	1,908,224	673	32.37	85.99
Roxboro 3	2,342,686	698	38.31	86.74
Roxboro 4	1,406,706	711	22.59	49.30

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, 2017 through March, 2018
Other Cycling Steam Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Asheville	1	584,089	192	34.73	73.22
Asheville	2	624,780	192	37.15	83.95
Roxboro	1	996,819	380	29.95	88.33

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, 2017 through March, 2018
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Asheville CT	163,987	370	93.85
Blewett CT	204	68	92.54
Darlington CT	142,058	895	75.43
Richmond County CT	1,764,333	921	87.48
Sutton CT	-113	76	100.00
Sutton Fast Start CT	138,730	92	90.81
Wayne County CT	191,175	960	96.03
Weatherspoon CT	1,130	164	83.58

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, 2017 through March, 2018
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Blewett	91,910	27.0	85.54
Marshall	5,234	4.0	33.15
Tillery	137,014	84.0	97.37
Walters	353,063	113.0	99.23

Notes:

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

Duke Energy Progress, LLC
(North Carolina Only)

FUEL EMF DEFICIENCY RIDER FED-1

APPLICABILITY

This Rider recovers the revenue deficiency due to the inclusion in rates of an expired fuel experience modification factor (EMF) from March 16 through May 30, 2018. This rider shall remain in effect for a fixed 12-month period expiring on and after November 30, 2019.

MONTHLY RATE

The rates shown below are included in the MONTHLY RATE provision in each schedule identified in the table below:

Rate Class	Rate Adjustment Factor (cents per kWh)
Residential Applicable to Schedules: RES, R-TOUD, & R-TOU	0.022
Small General Service Applicable to Schedules: SGS, SGS-TOUE, SGS-TOU-CLR, TSF & TSS	0.052
Medium General Service Applicable to Schedules: MGS, SGS-TOU, SI, CH-TOUE, GS-TES, APH-TES, CSG, CSE	0.068
Large General Service Applicable to Schedules: LGS, LGS-TOU, LGS-RTP	0.002
Lighting Applicable to Schedules: ALS, SLS, SLR & SFLS	(0.046)

* Billing Adjustment Factors, shown above, include a North Carolina regulatory fee.

Effective for service rendered on and after December 1, 2018
NCUC Docket No. E-2, Subs 1142 and 1173

Ward Workpaper 1
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period December 2018 - November 2019

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs	8,052,542	7,431,097	7,365,335	6,361,337	29,210,311
Cost	$ 53,911,370	$ 48,342,888	$ 52,040,505	$ 42,106,618	$ 196,401,382
$/MWhs	$ 6.6950	$ 6.5055	$ 7.0656	$ 6.6191	

Avg. $/MWhs	**$ 6.7237**
Cents per kWh	**0.6724**

	Unit		Dec'2018 - Nov'19
MDC			
	Brunswick 1	MW	938
	Brunswick 2	MW	932
	Harris 1	MW	932
	Robinson 1	MW	741
			3,543
Hours in Year			8,760
Generation in GWhs			
	Brunswick 1	GWh	8,053
	Brunswick 2	GWh	7,431
	Harris 1	GWh	7,365
	Robinson 1	GWh	6,361
			29,210
	Proposed Nuclear Capacity Factor		**94.1%**

Ward Workpaper 2
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period December 2018 - November 2019

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs with NERC applied	7,676,209	7,627,108	7,347,888	5,292,243	27,943,448
Hours	8,760	8,760	8,760	8,760	8,760
MDC	938	932	932	741	3,543
Capacity Factor-NERC 5yr Avg	0.9342	0.9342	0.9000	0.8153	
Cost ($)	$ 51,612,532	$ 51,282,388	$ 49,404,998	$ 35,583,455	$ 187,883,372

Avg. $/MWHs	**$ 6.7237**
Cents per kWh	**0.6724**

	Capacity Rating	NCF Rating	Weighted Average
Brunswick 1	938	0.9342	24.73
Brunswick 2	932	0.9342	24.57
Harris 1	932	0.9000	23.67
Robinson 1	741	0.8153	17.05
	3,543		**90.03**

Ward Workpaper 3
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation in MWhs
Billing Period December 2018 - November 2019

Resource Type		**Dec'18 - Nov'19**
Nuclear		29,089,426
Adjust for Higher Nuclear Capacity Factor		120,885
Adjusted Nuclear Total		29,210,311
Coal		5,842,453
Adjust for Higher Nuclear Capacity Factor		(120,885)
Adjusted Coal Total		5,721,568
Gas CT and CC Total		22,506,145
Total Hydro		606,686
Utility Owned Solar Generation		304,154
Total Net Generation		58,348,864
Purchases	2,063,173	
Purchases for REPS Compliance	3,026,065	
Purchases from Qualifying Facilities	3,410,393	
Allocated Economic Purchases	768,328	
Joint Dispatch purchases	1,051,034	10,318,993
Total Net Generation and Purchases		68,667,857
Sales Totals (intersystem sales, JDA sales)		(4,650,587)
Line Losses and Company Use		(1,883,902)
Total NC System Sales		**62,133,368**

Ward Workpaper 4
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Fuel Costs ($)
Billing Period December 2018 - November 2019

Resource Type		Dec'18 - Nov'19
Nuclear		195,637,911
Adjust for Higher Nuclear Capacity Factor		763,471
Adjusted Nuclear		196,401,382
Coal		195,939,163
Adjust for Higher Nuclear Capacity Factor		(4,054,124)
Adjusted Coal Total		191,885,039
Reagent and By-Product Costs		14,989,402
Gas CT and CC Total		653,485,803
Total Hydro		-
Utility Owned Solar Generation		-
Total Generation Costs		1,056,761,626
Purchases	71,395,237	
Purchases for REPS Compliance	187,595,597	
Purchases for REPS Compliance Capacity	38,515,117	
Purchases from Qualifying Facilities Energy	162,649,793	
Purchases from Qualifying Facilities Capacity	33,362,793	
Allocated Economic Purchases	19,703,265	
Fuel Transfer Purchases	28,928,103	
Joint Dispatch savings	(12,766,851)	
Total Purchase Costs		529,383,055
Sales Totals (intersystem sales)	(6,081,270)	
Fuel Transfer Sales	(99,268,979)	
Total Sales Costs		(105,350,249)
Total Fuel and Related Expenses		**1,480,794,432**

Ward Workpaper 5
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Fuel Impacts
Billing Period December 2018 - November 2019

Positive numbers represent costs to Rate Payers, Negative numbers represent removal of costs to ratepayers

	Allocated Economic Purchase Cost		Economic Sales Cost		Fuel Transfer Payment		JDA Savings Payment		Gas Savings Payment		Coal Savings Payment		Nuclear Savings Payment	
Date	**PEC**	**DEC**	**PEC**	**DEC**	**PEC**	**DEC**	**PEC**	**DEC**	**PEC**	**DEC**	**PEC**	**DEC**	**PEC**	**DEC**
12/1/2018	$ 1,345,873	$ 1,955,237	$ (140,930)	$ (83,850)	$ (9,189,225)	$ 9,189,225	$ (1,375,188)	$ 1,375,188	$ -	$ -	$ -	$ -	$ -	$ -
1/1/2019	$ 541,737	$ 745,107	$ (700,368)	$ (1,355,398)	$ 5,124,715	$ (5,124,715)	$ 1,728,069	$ (1,728,069)	$ -	$ -	$ -	$ -	$ -	$ -
2/1/2019	$ 479,661	$ 648,044	$ (252,787)	$ (478,599)	$ 4,986,493	$ (4,986,493)	$ 1,373,256	$ (1,373,256)	$ -	$ -	$ -	$ -	$ -	$ -
3/1/2019	$ 748,063	$ 1,054,241	$ (276,328)	$ (413,915)	$ (5,141,840)	$ 5,141,840	$ (602,037)	$ 602,037	$ -	$ -	$ -	$ -	$ -	$ -
4/1/2019	$ 1,392,702	$ 2,003,761	$ (86,557)	$ (4,897)	$ (10,088,094)	$ 10,088,094	$ (2,588,754)	$ 2,588,754	$ -	$ -	$ -	$ -	$ -	$ -
5/1/2019	$ 1,432,388	$ 2,134,064	$ (139,193)	$ (77,686)	$ (8,719,301)	$ 8,719,301	$ (1,820,155)	$ 1,820,155	$ -	$ -	$ -	$ -	$ -	$ -
6/1/2019	$ 2,825,496	$ 4,161,449	$ (141,931)	$ (207,604)	$ (8,410,050)	$ 8,410,050	$ (1,400,517)	$ 1,400,517	$ -	$ -	$ -	$ -	$ -	$ -
7/1/2019	$ 1,990,176	$ 2,806,745	$ (194,526)	$ (385,609)	$ (6,038,136)	$ 6,038,136	$ (2,238,685)	$ 2,238,685	$ -	$ -	$ -	$ -	$ -	$ -
8/1/2019	$ 2,704,270	$ 3,787,546	$ (82,066)	$ (186,361)	$ (4,051,006)	$ 4,051,006	$ 661,492	$ (661,492)	$ -	$ -	$ -	$ -	$ -	$ -
9/1/2019	$ 2,835,549	$ 3,919,422	$ (70,328)	$ (67,422)	$ (8,068,946)	$ 8,068,946	$ (1,385,455)	$ 1,385,455	$ -	$ -	$ -	$ -	$ -	$ -
10/1/2019	$ 1,783,526	$ 2,428,310	$ (42,634)	$ (20,186)	$ (2,932,457)	$ 2,932,457	$ (487,002)	$ 487,002	$ -	$ -	$ -	$ -	$ -	$ -
11/1/2019	$ 1,623,825	$ 2,408,602	$ (176,982)	$ (13,394)	$ (17,813,028)	$ 17,813,028	$ (4,631,873)	$ 4,631,873	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 19,703,265		$ (2,304,630)		$ (70,340,876)		$ (12,766,851)		$ -		$ -		$ -	

Note: Totals may not sum due to rounding

	Fuel Transfer Payments		
	Purchases	**Sales**	
12/1/2018	$ 1,142,030	$ 10,331,256	
1/1/2019	$ 7,776,073	$ 2,651,359	
2/1/2019	$ 8,278,838	$ 3,292,345	
3/1/2019	$ 3,548,261	$ 8,690,101	
4/1/2019	$ 341,351	$ 10,429,445	
5/1/2019	$ 699,389	$ 9,418,690	
6/1/2019	$ 490,598	$ 8,900,647	
7/1/2019	$ 1,743,100	$ 7,781,236	
8/1/2019	$ 1,727,214	$ 5,778,220	
9/1/2019	$ 720,534	$ 8,789,480	
10/1/2019	$ 2,448,887	$ 5,381,344	
11/1/2019	$ 11,829	$ 17,824,857	
	$ 28,928,103	$ 99,268,979	Workpaper 6
		$ (70,340,876)	

Ward Workpaper 6
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Payments
Billing Period December 2018 - November 2019

	Transfer Projection		Purchase Allocation Delta		Adjusted Transfer		Fossil Gen Cost		Pre-Net Payments		Actual Payments	
Date	**PEC to DEC**	**DEC to PEC**	**PEC**	**DEC**	**PEC to DEC**	**DEC to PEC**	**PEC**	**DEC**	**PEC to DEC**	**DEC to PEC**	**PEC to DEC**	**DEC to PEC**
12/1/2018	397,277	41,555	(381)	381	397,277	41,936	$ 26.01	$ 27.23	$ 1,142,030	$ 10,331,256	$ -	$ 9,189,225
1/1/2019	88,029	254,914	(8,444)	8,444	88,029	263,359	$ 30.12	$ 29.53	$ 7,776,073	$ 2,651,359	$ 5,124,715	$ -
2/1/2019	109,267	275,569	(12,598)	12,598	109,267	288,167	$ 30.13	$ 28.73	$ 8,278,838	$ 3,292,345	$ 4,986,493	$ -
3/1/2019	357,709	128,272	(4,538)	4,538	357,709	132,810	$ 24.29	$ 26.72	$ 3,548,261	$ 8,690,101	$ -	$ 5,141,840
4/1/2019	454,246	13,245	14,770	(14,770)	469,016	13,245	$ 22.24	$ 25.77	$ 341,351	$ 10,429,445	$ -	$ 10,088,094
5/1/2019	399,784	29,283	7,743	(7,743)	407,527	29,283	$ 23.11	$ 23.88	$ 699,389	$ 9,418,690	$ -	$ 8,719,301
6/1/2019	350,309	19,051	22,145	(22,145)	372,455	19,051	$ 23.90	$ 25.75	$ 490,598	$ 8,900,647	$ -	$ 8,410,050
7/1/2019	307,333	64,087	(910)	910	307,333	64,997	$ 25.32	$ 26.82	$ 1,743,100	$ 7,781,236	$ -	$ 6,038,136
8/1/2019	229,021	65,127	4,087	(4,087)	233,109	65,127	$ 24.79	$ 26.52	$ 1,727,214	$ 5,778,220	$ -	$ 4,051,006
9/1/2019	366,006	29,272	22,042	(22,042)	388,048	29,272	$ 22.65	$ 24.61	$ 720,534	$ 8,789,480	$ -	$ 8,068,946
10/1/2019	253,028	103,286	(33)	33	253,028	103,319	$ 21.27	$ 23.70	$ 2,448,887	$ 5,381,344	$ -	$ 2,932,457
11/1/2019	923,530	466	64,082	(64,082)	987,612	466	$ 18.05	$ 25.40	$ 11,829	$ 17,824,857	$ -	$ 17,813,028
	4,235,540	1,024,129			4,370,410	1,051,034			$ 28,928,103	$ 99,268,979		

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales
Billing Period December 2018 - November 2019

Spring 2018 Forecast

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC			
Residential	15,956,916		15,956,916
Small General Service	1,795,996		1,795,996
Medium General Service	10,351,641		10,351,641
Large General Service	9,176,034		9,176,034
Lighting	379,219		379,219
Total	37,659,805		37,659,805
SC Retail	6,666,325	21,344	6,687,669
Total Wholesale	17,807,238		17,807,238
Total Adjusted NC System Sales	62,133,368	21,344	62,154,712
NC as a percentage of total	60.61%	0.00%	60.59%
SC as a percentage of total	10.73%	100.00%	10.76%
Wholesale as a percentage of total	28.66%	0.00%	28.65%

SC Net Metering allocation adjustment		
Total Projected SC NEM MWhs	21,344	
Marginal Fuel rate per MWh for SC NEM	$ 32.06	
Fuel Benefit to be directly assigned to SC	$ 684,289	
System Fuel Expense	1,480,794,432	Ward Exhibit 2, Schedule 1, Page 1
Fuel benefit to be directly assigned to SC Retail	$ 684,289	
Total Adjusted System Fuel Expense	1,481,478,720	

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Normalized Sales
Billing Period December 2018 - November 2019

Spring 2018 Forecast

	Test Period Sales MWhs	Weather Normalization	Customer Growth	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC					
Residential	15,893,252	(408,572)	137,163		15,621,843
Small General Service	1,934,331	(54,664)	11,784		1,891,451
Medium General Service	11,124,532	(109,490)	23,604		11,038,646
Large General Service	8,384,692	(80,904)	42,341		8,346,128
Lighting	360,623	0	613		361,235
Total	37,697,429	(653,630)	215,505		37,259,304
SC Retail	6,353,202	(98,915)	4,557	21,344	6,280,188
Total Wholesale	18,402,520	(197,273)	147,596		18,352,843
Total Adjusted NC System Sales	62,453,151	(949,818)	367,658	21,344	61,892,335
NC as a percentage of total	60.36%				60.20%
SC as a percentage of total	10.17%				10.15%
Wholesale as a percentage of total	29.47%				29.65%

SC Net Metering allocation adjustment		21,344	
Total Projected SC NEM MWhs	$	32.06	
Marginal Fuel rate per MWh for SC NEM	$	684,289	
Fuel Benefit to be directly assigned to SC			
System Fuel Expense	$	1,471,710,965	Ward Exhibit 2, Schedule 2, page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$	684,289	
Total Adjusted System Fuel Expense	$	1,472,395,253	

Ward Workpaper 7b
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales - NERC 5 year Average
Billing Period December 2018 - November 2019

Spring 2018 Forecast

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC			
Residential	15,956,916		15,956,916
Small General Service	1,795,996		1,795,996
Medium General Service	10,351,641		10,351,641
Large General Service	9,176,034		9,176,034
Lighting	379,219		379,219
Total	37,659,805		37,659,805
SC Retail	6,666,325	21,344	6,687,669
Total Wholesale	17,807,238		17,807,238
Total Adjusted NC System Sales	62,133,368	21,344	62,154,712
NC as a percentage of total	60.61%	0.00%	60.59%
SC as a percentage of total	10.73%	100.00%	10.76%
Wholesale as a percentage of total	28.66%	0.00%	28.65%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs	21,344	
Marginal Fuel rate per MWh for SC NEM	$ 32.06	
Fuel Benefit to be directly assigned to SC	$ 684,289	
System Fuel Expense	1,514,763,382	Ward Exhibit 2, Schedule 3, Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 684,289	
Total Adjusted System Fuel Expense	1,515,447,671	

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
NC Retail Allocation %
Energy Allocation Factors - 12 Months Ending December 31, 2017

	kWh @ Meter	E-2 Allocation	kWh @ Prod Out.	E-1 Allocation
NC RES	14,637,333,282	0.240750	15,191,620,578	0.242266
NC RES-TOU	486,245,935	0.007998	504,659,121	0.008048
NC SGS	1,844,386,439	0.030336	1,914,220,716	0.030527
NC SGS-CLR	30,133,412	0.000496	31,274,506	0.000499
NC MGS-TOU	8,233,618,359	0.135424	8,536,022,048	0.136127
NC MGS	2,760,634,474	0.045406	2,863,468,664	0.045665
NC SI	51,779,687	0.000852	53,603,512	0.000855
NC LGS	1,145,912,181	0.018848	1,183,504,912	0.018874
NC LGS-TOU	1,661,914,071	0.027335	1,716,393,791	0.027372
NC LGS-RTP	5,608,836,997	0.092252	5,775,997,908	0.092112
NC TSS	4,917,974	0.000081	5,104,208	0.000081
NC ALS	276,265,920	0.004544	286,727,572	0.004573
NC SLS	86,757,985	0.001427	90,043,341	0.001436
NC SFLS	1,161,856	0.000019	1,200,652	0.000019
Total NCR	36,829,898,572	0.605765	38,153,841,530	0.608452
NCEMPA	7,301,615,320	0.120094	7,453,121,270	0.118857
NCEMC	7,431,239,052	0.122226	7,585,434,650	0.120967
Fayetteville	2,043,810,625	0.033616	2,086,218,976	0.033270
FBEMC	517,036,898	0.008504	527,765,232	0.008416
Piedmont EMC	65,490,426	0.001077	66,849,329	0.001066
Haywood EMC	71,534,846	0.001177	73,019,169	0.001164
Tri-Towns	72,323,029	0.001190	73,823,707	0.001177
Waynesville	-	0.000000	-	0.000000
Winterville	53,202,365	0.000875	54,306,296	0.000866
Total NCWHS	10,254,637,241	0.168665	10,467,417,358	0.166927
Total NC	54,386,151,132	0.894524	56,074,380,158	0.894236
SC RES	1,978,209,443	0.032537	2,053,120,381	0.032742
SC RET	40,124,603	0.000660	41,644,044	0.000664
SC SGS	266,717,007	0.004387	276,806,870	0.004414
SC SGS-CLR	4,147,619	0.000068	4,304,681	0.000069
SC MGS-TOU	1,102,797,227	0.018138	1,143,152,090	0.018230
SC MGS	529,245,596	0.008705	548,740,427	0.008751
SC SI	16,757,842	0.000276	17,338,385	0.000277
SC LGS	675,487,312	0.011110	697,836,088	0.011129
SC LGS-TOU	287,281,247	0.004725	296,025,780	0.004721
SC LGS-CRTL-TOU	681,470,500	0.011209	700,362,469	0.011169
SC LGS-RTP	556,970,460	0.009161	571,996,347	0.009122
SC TSS	855,647	0.000014	888,049	0.000014
SC ALS	66,112,583	0.001087	68,616,138	0.001094
SC SLS	17,160,829	0.000282	17,810,676	0.000284
SC SFLS	141,879	0.000002	146,617	0.000002
Total SCR	6,223,479,794	0.102362	6,438,789,041	0.102681
SCWHS (Camden)	189,347,622	0.003114	193,276,519	0.003082
Total SC	6,412,827,416	0.105476	6,632,065,560	0.105764
Total System	60,798,978,548	1.000000	62,706,445,718	1.000000

2017 Cost of Service Data

	kWh @ Meter	kWh @ Prod Out.	Losses (kWh)	Loss Percent
Residential	15,123,579,217	15,696,279,699	572,700,482	3.79%
SGS	1,879,437,825	1,950,599,430	71,161,605	3.79%
MGS	11,046,032,520	11,453,094,224	407,061,704	3.69%
LGS	8,416,663,249	8,675,896,612	259,233,363	3.08%
Lighting	364,185,761	377,971,565	13,785,804	3.79%
Total NC Retail	36,829,898,572	38,153,841,530	1,323,942,958	3.59%
Total NC Retail	36,829,898,572	38,153,841,530	1,323,942,958	3.59%
SC Retail	6,223,479,794	6,438,789,041	215,309,247	
NEM Generation	846,239	876,568	30,329	
Total SC Retail	6,224,326,033	6,439,665,609	215,339,576	3.46%
All other jurisdictions	17,744,753,944	18,112,938,579	368,184,635	2.07%
Total System	60,798,978,548	62,706,445,718	1,907,467,170	3.14%

Line Loss Calculations for Projected Fuel Costs

	MWh @ Meter	MWh @ Prod Out.	Losses (MWh)	Loss Percent
Total NC Retail	37,659,805	39,064,061	1,404,256	3.73%
Total SC Retail	6,687,669	6,927,330	239,661	3.58%
All other jurisdictions	17,807,238	18,184,548	377,310	2.12%
Total System	62,154,712	64,175,938	2,021,226	3.25%
Allocation percent - NC retail	60.59%	60.87%		

Line Loss Calculations for Normalized Test Period Sales

	MWh @ Meter	MWh @ Prod Out.	Losses (MWh)	Loss Percent
Total NC Retail	37,259,304	38,648,625	1,389,322	3.73%
Total SC Retail	6,280,188	6,505,246	225,058	3.58%
All other jurisdictions	18,352,843	18,741,713	388,870	2.12%
Total System	61,892,335	63,895,585	2,003,251	3.24%
Allocation percent - NC retail	60.20%	60.49%		

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 - Year Ended March 31, 2017

										Remove Partial Year Impacts						Add Impact of Approved Rate Changes During Test Year					
Revenue Class (1)		Annual Sales (2) per RMC2B	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 2018 EE Rate (11) per RMCRY14	Opt-Out Credit Due to Jan. 2018 DSM Rate (12) per RMCRY15	NC Rate Case - Mar. 16, 2018 (13) per Report PMCM7M Worksheet	REPS Revenue Due to December 2017 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 1/18 EE Rate (17) = (3) * Rate Change	Annual Opt-Out Impact of 1/18 EE Rate (18) = (4) * Rate Change	NC Rate Case - Mar. 16, 2018 (19) per Report PMCM7M Worksheet	Annual Impact of Dec. 2017 REPS Rate (20) = (8) * Rate Change	Annual Revenue At Current Rates (21)=(15)+[16-17-18]+(19)+(20)
Residential		15,960,038,395	0	0	14,522,352	15,960,038,395	0	14,421,450	$1,653,156,530	$20,706,069	$0	$0	$1,273,775	($3,012,860)	$1,634,189,546	$48,337,554	$0	$0	$101,559,115	($10,671,873)	$1,773,414,341
	Residential	15,893,249,426	0	0	14,407,731	15,893,249,426	0	14,341,989	$1,631,725,961	$20,559,281	$0	$0	$1,280,863	($2,996,610)	$1,612,882,428	$47,817,963	$0	$0	$102,197,901	($10,613,072)	$1,752,285,220
	SGS	11,685	0	0	15	11,685	0	0	$1,217	$18	$0	$0	$1	($0)	$1,199	$74	$0	$0	$66	$0	$1,339
	MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$1	-$1	$0	$0	$0	$0	$0	-$1
	LGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Lighting	66,777,284	0	0	114,606	66,777,284	0	79,461	$21,429,351	$146,770	$0	$0	($7,088)	($16,250)	$21,305,920	$519,517	$0	$0	($638,852)	($58,801)	$21,127,783
Commercial		12,350,308,462	3,935,452,080	4,025,132,062	2,438,520	2,190,803,254	30,243,757	2,334,379	$1,022,488,248	$13,578,767	($150,188)	($67,505)	$361,536	($2,803,289)	$1,011,133,541	$58,618,615	($981,341)	($441,379)	$35,369,346	($9,897,767)	$1,096,646,455
	Residential	2,735	0	0	42	2,735	0	0	$408	$4	$0	$0	$0	($33)	$437	$13	$0	$0	$22	$0	$471
	SGS	1,910,167,597	14,371,573	15,025,127	1,988,048	1,910,167,597	0	1,793,489	$206,144,634	$3,607,533	($673)	($308)	$111,383	($2,152,495)	$204,577,232	$12,005,677	($3,593)	($1,653)	$11,244,288	($7,604,394)	$220,228,049
	MGS	9,075,753,440	2,809,369,913	2,906,509,030	436,038	61,471,343	28,046,973	391,635	$688,977,933	$8,651,652	($109,475)	($49,975)	$251,862	($472,206)	$680,387,176	$41,617,705	($702,342)	($319,716)	$23,133,373	($1,660,534)	$744,499,779
	LGS	1,145,223,111	1,099,702,567	1,090,999,104	1,109	0	2,196,783	904	$79,226,206	$839,399	($39,965)	($17,222)	$17,962	($1,056)	$78,312,714	$3,290,216	($274,926)	($120,010)	$2,762,211	($3,831)	$84,756,245
	Lighting	219,161,579	12,008,027	12,598,801	13,283	219,161,579	0	148,351	$48,139,068	$480,180	($75)	$0	($19,671)	($177,499)	$47,855,983	$1,705,004	($480)	$0	($1,770,548)	($629,008)	$47,161,910
Industrial		7,897,296,247	7,747,982,502	7,793,134,961	42,237	35,569,676	16,443,510	22,920	$485,572,150	$6,040,180	($258,190)	($114,122)	$107,831	($159,645)	$479,211,471	$25,713,469	($1,935,205)	($856,263)	$17,732,689	($561,540)	$524,887,558
	Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SGS	19,668,936	7,954,821	8,000,491	12,505	19,668,936	0	3,684	$1,940,258	$40,294	($386)	($171)	$1,045	($25,124)	$1,923,486	$123,663	($1,989)	($880)	$105,661	($90,269)	$2,065,409
	MGS	2,048,763,216	1,445,049,703	1,458,719,795	27,232	429,167	5,923,082	15,856	$146,811,944	$1,864,876	($58,534)	($25,831)	$54,140	($110,841)	$144,919,403	$9,041,131	($361,262)	($160,459)	$4,839,938	($388,480)	$158,933,714
	LGS	5,813,392,522	6,286,452,071	6,317,492,923	2,302	0	10,520,428	1,744	$334,221,274	$4,101,563	($199,216)	($88,120)	$53,787	($12,857)	$329,791,445	$16,428,535	($1,571,613)	($694,924)	$12,889,995	($42,721)	$361,333,790
	Lighting	15,471,573	8,525,907	8,921,752	198	15,471,573	0	1,636	$2,598,674	$33,447	($55)	$0	($1,142)	($10,823)	$2,577,137	$120,140	($341)	$0	($102,904)	($40,070)	$2,554,645
Public Streets & Highways		63,707,873	0	0	11,209	63,707,873	0	10,373	$16,349,407	$135,770	$0	$0	($69)	($12,021)	$16,225,728	$482,371	$0	$0	($6,207)	($43,982)	$16,657,910
	Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SGS	4,498,044	0	0	5,591	4,498,044	0	5,509	$370,395	$6,001	$0	$0	$411	($6,163)	$370,146	$22,096	$0	$0	$37,060	($23,359)	$405,942
	MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	LGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Lighting	59,209,829	0	0	5,618	59,209,829	0	4,864	$15,979,012	$129,768	$0	$0	($480)	($5,859)	$15,855,582	$460,275	$0	$0	($43,267)	($20,622)	$16,251,968
Military		1,426,645,680	1,528,610,570	1,528,610,570	48	1,920	2,806,407	48	$84,840,543	$717,271	($26,335)	($11,587)	$11,229	($298)	$84,074,419	$4,102,618	($382,153)	($168,147)	$3,458,973	($1,176)	$92,185,134
	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	1,426,643,760	1,528,610,570	1,528,610,570	48	0	2,806,407	48	$84,840,339	$717,267	($26,335)	($11,587)	$11,229	($298)	$84,074,218	$4,102,603	($382,153)	($168,147)	$3,458,982	($1,176)	$92,184,926
	Lighting	1,920	0	0	0	1,920	0	0	$204	$4	$0	$0	($0)	$0	$201	$15	$0	$0	($8)	$0	$207
NC Retail		37,697,996,657	13,212,045,152	13,346,877,593	17,014,366	18,250,121,118	49,493,673	16,789,170	$3,262,406,879	$41,178,057	($434,714)	($193,214)	$1,754,303	($5,988,114)	$3,224,834,704	$137,254,627	($3,298,699)	($1,465,789)	$158,113,917	($21,176,337)	$3,503,791,399
	check	0	0	0	0	0	0		0	$0	0	0	0	0		0			0		
Rate Schedules (excludes REPS)																					
RES (includes RES-RECD)		15,388,721,010	0	0	14,117,629	15,388,721,010	0		$1,587,171,936	$20,118,981	$0	$0	$1,248,390	-$2,996,643	$1,568,801,208	$52,418,676	$0	$0	$0		$1,621,219,884
SGS		1,895,049,342	22,326,394	23,025,618	1,919,906	1,895,049,342	0		$204,198,373	$3,589,325	($1,059)	($479)	$222,857	-$2,082,059	$202,466,712	$11,931,897	($5,582)	($2,533)	$0		$214,406,723
MGS		2,764,230,842	330,245,396	334,258,741	197,927	0	13,212,174		$255,905,190	$4,526,292	($12,680)	($5,699)	$391,568	-$255,661	$251,224,612	$15,852,835	($82,561)	($36,768)	$0		$267,196,777
SGS-TOU		8,276,146,684	3,916,964,842	4,023,727,558	253,933	0	20,710,064		$571,803,788	$5,926,536	($155,157)	($70,030)	$218,106	-$318,195	$565,752,154	$34,262,015	($979,241)	($442,610)	$0		$601,436,020
LGS		1,141,763,777	1,056,003,480	1,080,040,332	1,125	0	2,493,111		$83,778,472	$922,685	($38,933)	($17,400)	$98,938	-$5,340	$82,705,855	$3,590,708	($264,001)	($118,804)	$0		$86,679,368
LGS-TOU		1,644,168,024	1,702,574,797	1,700,875,334	1,400	0	2,931,348		$109,594,302	$1,275,259	($64,905)	($28,390)	$26,761	-$4,217	$108,203,203	$4,671,627	($425,644)	($187,096)	$0		$113,487,570
LGS-RTP		1,960,708	1,960,708	1,960,708	11	0	37,752		$749,149	$8,127	($259)	($114)	$0	-$25	$740,674	$31,317	($490)	($216)	$0		$772,697
LGS-RTP-TOU		5,597,366,884	6,154,226,223	6,154,226,223	923	0	10,061,407		$304,165,896	$3,452,159	($161,419)	($71,024)	$40,258	-$4,630	$300,445,666	$15,527,702	($1,538,557)	($676,965)	$0		$318,188,889
LGS Class		8,385,259,393	8,914,765,208	8,937,102,597	3,459	0	15,523,618		$498,287,819	$5,658,229	($265,517)	($116,929)	$165,957	($14,211)	$492,095,398	$23,821,354	($2,228,691)	($983,081)	$0		$519,128,525
<u>Rate Class</u>																					
Residential		15,893,252,161	0	0	14,407,773	15,893,252,161	0	14,341,989	$1,631,726,369	$20,559,285	$0	$0	$1,280,863	($2,996,643)	$1,612,882,864	$47,817,976	$0	$0	$102,197,923	($10,613,072)	$1,752,285,692
SGS		1,934,346,262	22,326,394	23,025,618	2,006,159	1,934,346,262	0	1,802,683	$208,456,504	$3,653,846	($1,059)	($479)	$112,841	($2,183,783)	$206,872,062	$12,151,509	($5,582)	($2,533)	$11,387,075	($7,718,022)	$222,700,739
MGS		11,124,516,656	4,254,419,616	4,365,228,825	463,270	61,900,510	33,970,055	407,492	$835,789,877	$10,516,528	($168,008)	($75,806)	$306,002	($583,046)	$825,306,578	$50,658,836	($1,063,605)	($480,175)	$27,973,311	($2,049,013)	$903,433,492
LGS		8,385,259,393	8,914,765,208	8,937,102,597	3,459	0	15,523,618	2,695	$498,287,819	$5,658,229	($265,517)	($116,929)	$82,979	($14,211)	$492,178,377	$23,821,354	($2,228,691)	($983,081)	$19,111,187	($47,729)	$538,274,962
Lighting		360,622,185	20,533,934	21,520,553	133,705	360,622,185	0	234,312	$88,146,309	$790,169	($130)	$0	($28,381)	($210,431)	$87,594,823	$2,804,951	($821)	$0	($2,555,579)	($748,502)	$87,096,514
		37,697,996,657	13,212,045,152	13,346,877,593	17,014,366	18,250,121,118	49,493,673	16,789,170	$3,262,406,879	$41,178,057	($434,714)	($193,214)	$1,754,303	($5,988,114)	$3,224,834,704	$137,254,627	($3,298,699)	($1,465,789)	$158,113,917	($21,176,337)	$3,503,791,399
Check		0	0	0	0	0	0	0	0	$0	0	0	0	0	0	0	0	0	0	0	0

Ward Workpaper 10
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Actual Sales by Jurisdiction - Subject to Weather
Twelve Months Ended March 31, 2018
MWH

Line #	Description	Reference	NORTH CAROLINA	SOUTH CAROLINA	Retail TOTAL COMPANY	% NC	% SC
1	Residential	Company Records	15,960,038	2,134,908	18,094,947	88.20	11.80
2	Commercial	Company Records	12,350,308	1,713,501	14,063,810	87.82	12.18
3	Industrial	Company Records	7,896,728	2,442,440	10,339,168	76.38	23.62
4	Other Public Authority	Company Records	1,426,646	47,368	1,474,013	96.79	3.21
5	Total Retail Sales subject to weather	Sum 1 through 4	37,633,721	6,338,217	43,971,938		
6	Lighting	Company Records	63,708	14,985	78,693		
7	Total Retail Sales subject to weather	Line 5 + Line 6	37,697,429	6,353,202	44,050,631		

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Adjustment - MWh
Twelve Months Ended March 31, 2018

Line #	Description	REFERENCE	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Residential		(463,234)	88.20	(408,572)	11.80	(54,662)
	Commercial						
2	Small and Medium General Service		(186,921)	87.82	(164,154)	12.18	(22,767)
	Industrial						
3	Large General Service		(89,172)	76.38	(68,110)	23.62	(21,062)
	OPA						
4	Other Public Authority (Large General Service)		(13,218)	96.79	(12,794)	3.21	(424)
5	Total Retail	L1+ L2+ L3 + L4	(752,544)		(653,630)		(98,915)
6	Wholesale		(197,273)				
7	Total Company	L5 + L6	(949,818)		(653,630)		(98,915)

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, 2018

	Total MWH Residential Adjustment	Total MWH Commercial Adjustment	Total MWH Industrial Adjustment	Total MWH OPA Adjustment	Total MWHs
Apr-17	43,301	0	8,977	0	52,279
May-17	(83,133)	0	0	0	(83,133)
Jun-17	(181,673)	(72,685)	(22,292)	(4,448)	(281,098)
Jul-17	(120,803)	(37,364)	(16,310)	(3,640)	(178,117)
Aug-17	(85,189)	(32,858)	(16,440)	(4,159)	(138,646)
Sep-17	86,938	39,136	9,825	4,533	140,432
Oct-17	(98,436)	(45,155)	(40,938)	(6,522)	(191,051)
Nov-17	24,601	0	0	0	24,601
Dec-17	(1,534)	0	0	0	(1,534)
Jan-18	(333,869)	(37,994)	(11,994)	0	(383,857)
Feb-18	82,652	0	0	1,016	83,668
Mar-18	203,912	0	0	0	203,912
Total	**(463,234)**	**(186,921)**	**(89,172)**	**(13,218)**	**(752,544)**

Wholesale Weather Adjustment	MWH
Apr-17	228
May-17	(11,168)
Jun-17	(55,686)
Jul-17	(34,162)
Aug-17	(30,326)
Sep-17	22,829
Oct-17	2,525
Nov-17	14,415
Dec-17	7,398
Jan-18	(194,756)
Feb-18	5,069
Mar-18	76,360
Total	**(197,273)**

Ward Workpaper 12
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adustment - MWh
Twelve Months Ended March 31, 2018

Rate Schedule	Reference	NC Proposed KWH [1] Adjustment	SC Proposed KWH Adjustment	Wholesale Proposed KWH Adjustment
Residential	RES	137,163,199	7,293,996	
General:				
General Service Small	SGS	11,784,474	139,247	
General Service Medium	MGS	23,603,834	(2,915,568)	
Total General		35,388,308	(2,776,321)	
Lighting:				
Street Lighting	SLS/SLR	421,060	38,032	
Sports Field Lighting	SFLS	46,843	1,087	
Traffic Signal Service	TSS/TFS	144,824	-	
Total Street Lighting		612,727	39,119	
Industrial:				
I - Textile	LGS	1,357,530	-	
I - Nontextile	LGS	40,982,999	-	
Total Industrial		42,340,529	-	
Total		**215,504,763**	**4,556,794**	**147,596,126**

[1] Using the regression method (Residential, Lighting, SGS classes) and a customer by customer method for MGS and Industrial

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Reagents
Billing Period December 2018 - November 2019
($)

Date	Ammonia	Limestone	Limestone Off-System Sales	Catalyst Depreciation	Magnesium hydroxide	Calcium Carbonate	Total NC System Reagent Cost $	Gypsum (Gain)/Loss$	Ash (Gain)/Loss $	Total NC System Reagent Cost and ByProduct (Gain)/Loss $
12/1/18	$ 136,259	$ 510,002	(6,857)	$ 364,466	$ 112,631	$ 57,943	$ 1,174,443	$ (21,499)	$ (1,435)	$ 1,151,510
1/1/19	466,205	1,576,890	(38,351)	364,466	481,522	213,712	3,064,444	(151,153)	(8,863)	2,904,427
2/1/19	372,520	1,296,381	(19,446)	364,466	376,083	174,781	2,564,785	(113,752)	(6,837)	2,444,196
3/1/19	90,404	332,996	(9,449)	364,466	88,337	40,627	907,380	(22,588)	(1,498)	883,295
4/1/19	6,762	26,551	(1,038)	364,466	3,971	2,617	403,330	(2,682)	(131)	400,517
5/1/19	47,919	201,433	(9,810)	364,466	40,426	24,129	668,563	(4,944)	(648)	662,972
6/1/19	141,184	560,225	(14,675)	364,466	146,523	76,334	1,274,056	(15,063)	(2,079)	1,256,914
7/1/19	240,795	920,886	(20,479)	364,466	265,612	124,141	1,895,420	(34,392)	(3,796)	1,857,232
8/1/19	188,602	743,336	(12,176)	364,466	202,957	99,816	1,587,002	(18,513)	(2,769)	1,565,720
9/1/19	70,739	292,768	(8,022)	364,466	76,998	35,632	832,581	(4,771)	(943)	826,867
10/1/19	17,314	92,264	(3,628)	364,466	8,697	2,138	481,250	(2,131)	(105)	479,014
11/1/19	29,663	114,311	(1,676)	364,466	35,172	19,535	561,472	(4,206)	(526)	556,740
Total	$ 1,808,367	$ 6,668,042	$ (145,607)	$ 4,373,590	$ 1,838,929	$ 871,405	$ 15,414,726	$ (395,693)	$ (29,631)	$ 14,989,402

Ward Workpaper 14
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Billing Period December 2018 - November 2019

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 310,910,776	$ 78,097,747	$ 389,008,523
2	Amount in 2017 Filing: Docket E-2 Sub 1146[1]	$ 189,044,284	$ 63,374,757	$ 252,419,041
3	Increase/(Decrease)	$ 121,866,491	$ 14,722,990	$ 136,589,482
4	2.5% of 2017 NC revenue of $3,174,203,935			$ 79,355,098
5	Amount over 2.5%			$ 57,234,383

[1] Updated for Ward Supplemental filing from E-2, Sub 1146

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases	$ 71,395,237	60.59%	$ 43,258,374
WP 4	Purchases for REPS Compliance	187,595,597	60.59%	113,664,172
WP 4	Purchases for REPS Compliance Capacity	38,515,117	60.52%	23,309,349
WP 4	Purchases from Qualifying Facilities Energy	162,649,793	60.59%	98,549,509
WP 4	Purchases from Qualifying Facilities Capacity	33,362,793	60.52%	20,191,162
WP 4	Allocated Economic Purchases	19,703,265	60.59%	11,938,208
	Total	$ 513,221,803		$ 310,910,776

Revision of prior year amount based on Supplemental filing

	System Cost	Alloc %	NC Alloc. Forecast
Purchases	$ 41,519,620	60.35%	$ 25,057,091
Purchases for REPS Compliance	154,215,192	60.35%	93,068,868
Purchases for REPS Compliance Capacity	31,684,006	59.73%	18,924,857
Purchases from Qualifying Facilities Energy	55,113,822	60.35%	33,261,192
Purchases from Qualifying Facilities Capacity	11,792,060	59.73%	7,043,397
Allocated Economic Purchases	19,368,483	60.35%	11,688,879
Total	$ 313,693,183		$ 189,044,284

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Normalized
Billing Period December 2018 - November 2019

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 309,190,377	$ 78,097,747	$ 387,288,125
2	Amount in 2017 Filing: Docket E-2 Sub 1146[1]	$ 189,827,914	$ 63,374,757	$ 253,202,671
3	Increase/(Decrease)	$ 119,362,463	$ 14,722,990	$ 134,085,454
4	2.5% of 2017 NC revenue of $3,174,203,935			$ 79,355,098
5	Amount over 2.5%			$ 54,730,355

[1] Updated for Ward Supplemental filing from E-2, Sub 1146

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases	$ 71,395,237	60.20%	$ 42,980,069
WP 4	Purchases for REPS Compliance	187,595,597	60.20%	112,932,908
WP 4	Purchases for REPS Compliance Capacity	38,515,117	60.52%	23,309,349
WP 4	Purchases from Qualifying Facilities Energy	162,649,793	60.20%	97,915,486
WP 4	Purchases from Qualifying Facilities Capacity	33,362,793	60.52%	20,191,162
WP 4	Allocated Economic Purchases	19,703,265	60.20%	11,861,403
	Total	$ 513,221,803		$ 309,190,377

Revision of prior year amount based on Supplemental filing

	System Cost	Alloc %	NC Alloc. Forecast
Purchases	$ 41,519,620	60.64%	$ 25,177,498
Purchases for REPS Compliance	154,215,192	60.64%	93,516,092
Purchases for REPS Compliance Capacity	31,684,006	59.73%	18,924,857
Purchases from Qualifying Facilities Energy	55,113,822	60.64%	33,421,022
Purchases from Qualifying Facilities Capacity	11,792,060	59.73%	7,043,397
Allocated Economic Purchases	19,368,483	60.64%	11,745,048
Total	$ 313,693,183		$ 189,827,914

Ward Workpaper 14b
Docket No. E-2, Sub 1173

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test-Detail Calculation
Test Period April 2017 - March 2018

Line No.		Reference	Apr'17	May'17	Jun'17	July'17	Aug'17	Sept'17	Oct'17	Nov'17	Dec'17	Jan'18	Feb'18	Mar'18	12ME
1	System kWh Sales, at generation		4,335,469,861	4,932,060,728	5,397,868,365	6,394,006,650	6,129,821,550	5,549,643,007	5,017,553,777	4,653,732,667	5,207,790,989	7,032,183,930	5,204,248,102	4,819,034,998	64,673,414,626
2	NC Retail kWh Sales, at generation		2,663,685,856	3,008,839,284	3,282,066,550	3,763,834,590	3,709,727,456	3,514,356,608	3,115,790,642	2,808,636,488	3,033,319,652	4,196,552,990	3,385,261,956	2,886,386,827	39,368,458,899
3	NC Retail % of Sales	Line 2 / Line 1	61.44%	61.01%	60.80%	58.87%	60.52%	63.33%	62.10%	60.35%	58.25%	59.68%	65.05%	59.90%	60.87%
	Total Purchase Power, Excl. JDA														
4	System Purchase Power, Excl. JDA		$ 19,605,883	$ 19,900,277	$ 23,293,686	$ 23,935,064	$ 31,402,589	$ 27,105,426	$ 28,956,167	$ 24,226,365	$ 22,710,979	$ 47,646,530	$ 29,119,449	$ 24,815,849	$ 322,718,264
5	NC Purchase Power	Line 4 * Line 3	$ 12,045,733	$ 12,140,308	$ 14,163,263	$ 14,089,385	$ 19,004,639	$ 17,164,732	$ 17,981,144	$ 14,621,177	$ 13,228,192	$ 28,433,725	$ 18,941,634	$ 14,863,585	$ 196,677,518
6	NC Retail kWh Sales		2,551,835,593	2,882,501,392	3,143,064,984	3,603,204,650	3,552,280,447	3,365,321,674	2,985,024,507	2,690,884,704	2,903,934,765	4,015,062,214	3,240,479,595	2,763,834,319	37,697,428,844
7	Incurred Rate	Line 5 / Line 6 * 100	0.472	0.421	0.451	0.391	0.535	0.510	0.602	0.543	0.456	0.708	0.585	0.538	0.522
	Total Capacity														
8	System Capacity		$ 3,203,713	$ 3,162,059	$ 5,176,207	$ 4,741,869	$ 7,841,805	$ 6,928,942	$ 5,334,274	$ 3,517,629	$ 3,901,444	$ 2,570,154	$ 4,995,820	$ 3,511,619	$ 54,885,535
9	NC Capacity	Capacity*.5973	$ 1,913,578	$ 1,888,698	$ 3,091,749	$ 2,832,318	$ 4,683,910	$ 4,138,657	$ 3,186,162	$ 2,101,080	$ 2,330,333	$ 1,535,153	$ 2,984,003	$ 2,097,490	$ 32,783,130
10	NC Retail kWh Sales	Line 6	2,551,835,593	2,882,501,392	3,143,064,984	3,603,204,650	3,552,280,447	3,365,321,674	2,985,024,507	2,690,884,704	2,903,934,765	4,015,062,214	3,240,479,595	2,763,834,319	37,697,428,844
11	Incurred Rate	Line 12/Line 13*100	0.075	0.066	0.098	0.079	0.132	0.123	0.107	0.078	0.080	0.038	0.092	0.076	0.087
12	Total Incurred Rate	Line 7 + Line 11	0.547	0.487	0.549	0.470	0.667	0.633	0.709	0.621	0.536	0.746	0.677	0.614	0.609
13	Billed Rate	Billed Rates Below	0.370	0.370	0.370	0.370	0.415	0.415	0.415	0.415	0.419	0.424	0.425	0.402	
14	(Over)/Under cents per kwh	Line 13 - Line 12	0.177	0.117	0.179	0.099	0.252	0.218	0.294	0.207	0.117	0.322	0.252	0.212	
15	(Over)/Under $	Line 14 * Line10 /100	4,513,632	3,359,360	5,620,883	3,584,357	8,956,784	7,346,965	8,788,023	5,562,811	3,396,644	12,946,039	8,163,430	5,858,819	78,097,747

	Billed Rate from Docket E-2, Sub 1107 - Apr'17-Nov'17		
16	Purchases (Other Purchases + Economic Purchases)	60,801,776	McGee Workpaper 4 + 5
17	MWH Sales	62,219,566	McGee Workpaper 3
18	Billed Rate for Purchases	**0.098**	
19	Renewables	140,601,055	McGee Workpaper 4
20	MWH Sales	62,219,566	McGee Workpaper 3
21	Billed Rate for Renewables	**0.226**	
22	Capacity	28,904,344	Revised McGee Exhibit 2, Schedule 2
23	MWH Sales	62,219,566	McGee Workpaper 3
24	Billed Rate for Capacity	**0.046**	
25	Total Billed Rate	**0.370**	
26	QF PURPA Purchases included in base rates (August 2017 - November 2017)	0.045	
27	Total Billed Rate (August 2017 - November 2017)	**0.415**	
	Billed Rate from Docket E-2, Sub 1146 - Dec'17-Mar'18		
28	Purchases (Other Purchases + Economic Purchases)	60,888,103	Ward Workpaper 4
29	MWH Sales	68,022,851	Ward Workpaper 3
30	Billed Rate for Purchases	**0.090**	
31	Renewables	154,215,192	Ward Workpaper 4
32	MWH Sales	68,022,851	Ward Workpaper 3
33	Billed Rate for Renewables	**0.227**	
34	QF Purchases	55,113,822	Ward Workpaper 4
35	MWH Sales	68,022,851	Ward Workpaper 3
36	Billed Rate for Renewables	**0.081**	
37	Capacity (REPS and QF)	43,476,066	Ward Workpaper 4
38	MWH Sales	68,022,851	Ward Workpaper 3
39	Billed Rate for Capacity	**0.064**	
40	Total Billed Rate	0.380	
41	QF PURPA Purchases included in base rates (February 2018)	0.045	
42	Total Billed Rate (February 2018)	**0.425**	
43	QF PURPA Purchases included in base rates (new base rates March 15, 2018)	0.022	
44	Total Billed Rate (March 2018)	**0.402**	

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

Prior Bill Rate (Sub 1107)	0.370
Ratios of Days to rate	58.99%
Prorated Rate	**0.218**
New Bill Rate (Sub 1146)	0.380
Ratios of Days to rate	41.01%
Prorated Rate	**0.156**
Total Blended Rate for December	0.374
QF PURPA Purchases in base rates (Dec 2017)	0.045
Total Blended Billed Rate (Dec 2017)	**0.419**

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

Prior Bill Rate (Sub 1107)	0.370
Ratios of Days to rate	7.23%
Prorated Rate	**0.027**
New Bill Rate (Sub 1146)	0.380
Ratios of Days to rate	92.77%
Prorated Rate	**0.353**
Total Blended Rate for January	0.379
QF PURPA Purchases in base rates (Jan 2018)	0.045
Total Blended Billed Rate (Jan 2018)	**0.424**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1173

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**ERIC S. GRANT 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 Eric S. Grant. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Electrical Engineering from North Carolina State University. I joined Progress Energy in 1990, as an engineer in the Nuclear Engineering Department. From 2000-2006, I held a variety of management positions within Progress Energy's System Planning and Operations Department, including managing system operations for what is now DEP and Duke Energy Florida (DEF). In 2007, I became General Manager for the DEF Combined Cycle and Combustion Turbine Generation Fleet. I joined Duke Energy in July 2012 as the Managing Director of System Optimization, the position which I held until April 2017. I assumed my current position in April 2017. I am also a licensed professional engineer in the state of North

Carolina.

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

A. Yes. I testified in support of DEC's 2017 fuel and fuel-related cost recovery application in Docket No. E-7, Sub, 1163.

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, 2017 through March 31, 2018 ("test period") versus the period April 1, 2016 through March 31, 2017 ("prior test period"), and describe changes projected for the billing period of December 1, 2018 through November, 30 2019 ("billing period").

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

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Grant Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Grant 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 Grant Exhibit 3, which summarizes the fuels related transactional activity between DEC and Piedmont Natural Gas Company, Inc. ("Piedmont") for spot commodity transactions during the test period, as required by the Merger Agreement between Duke Energy and Piedmont, of which DEP receives an allocated portion based on its pro rata share of the overall gas plant burns for the respective month.

Q. 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 $80.82 per ton, compared to $80.26 per ton in the prior test period, representing an increase of approximately 1%. This includes an average transportation cost of $29.42 per ton in the test period, compared to $28.03 per ton in the prior test period, representing an increase of approximately 5%. The Company's average price of gas purchased for the test period was $4.68 per Million British Thermal Units ("MMBtu"), compared to $4.00 per MMBtu in the prior test period, representing an increase of approximately 17%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEP's coal burn for the test period was 3.9 million tons, compared to a coal burn of 4.7 million tons in the prior test period, representing a decrease of approximately 16%. The Company's natural gas burn for the test period was 169.4 million MMBtu, compared to a gas burn of 170.0 million MMBtu in the prior test period, representing a decrease of approximately 0.4%. The primary contributing factors were changes in (1) weather driven demand, and (2) commodity prices.

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

A. Coal markets continue to be in a state of flux due to a number of factors, including: (1) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) continued changes in global market demand for both steam and metallurgical coal; (4) uncertainty surrounding regulations for mining operations; and (5) 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 2.3 million tons, compared to 3.9 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $81.65 per ton for the billing period compared to $80.82 per ton in the test period. This cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEP is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEP's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

DEP's current natural gas burn projection for the billing period is approximately 171.8 million MMBtu, which is an increase from the 169.4 million MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.81 per MMBtu, compared to $3.03 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. 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, 2103, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for the combined Carolinas gas fleet.

Fuel Oil

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

DUKE ENERGY PROGRESS
Summary of Coal Purchases
Twelve Months Ended March 2018 & 2017
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
1	April 2017	223,875	0	223,875
2	May	224,952	0	224,952
3	June	238,854	12,264	251,118
4	July	320,213	0	320,213
5	August	430,436	0	430,436
6	September	346,651	0	346,651
7	October	325,000	0	325,000
8	November	324,889	0	324,889
9	December	229,150	0	229,150
10	January 2018	212,233	0	212,233
11	February	235,368	0	235,368
12	March	260,527	326	260,853
13	**Total** (Sum L1:L12)	**3,372,148**	**12,590**	**3,384,738**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
14	April 2016	243,140	0	243,140
15	May	240,749	0	240,749
16	June	251,139	0	251,139
17	July	367,433	0	367,433
18	August	496,536	0	496,536
19	September	505,889	0	505,889
20	October	392,494	41	392,535
21	November	525,819	0	525,819
22	December	494,298	12,899	507,197
23	January 2017	319,044	72,713	391,757
24	February	284,208	29,067	313,275
25	March	191,908	13,396	205,304
26	**Total** (Sum L14:L25)	**4,312,657**	**128,116**	**4,440,773**

DUKE ENERGY PROGRESS
Summary of Gas Purchases
Twelve Months Ended March 2018 & 2017
MBTUs

Line No.	Month	MBTUs
1	April 2017	11,260,572
2	May	11,466,510
3	June	13,517,327
4	July	15,763,956
5	August	15,138,794
6	September	13,928,655
7	October	12,729,705
8	November	14,540,861
9	December	16,817,106
10	January 2018	14,446,004
11	February	13,775,980
12	March	15,986,353
13	**Total** (Sum L1:L12)	**169,371,823.0**

Line No.	Month	MBTUs
14	April 2016	14,115,727
15	May	14,616,922
16	June	14,111,918
17	July	16,564,902
18	August	17,177,486
19	September	12,559,298
20	October	9,919,151
21	November	14,384,387
22	December	13,607,974
23	January 2017	13,786,819
24	February	14,028,144
25	March	14,884,889
26	**Total** (Sum L14:L25)	**169,757,617**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1173

In the Matter of	)
Application of Duke Energy Progress, LLC	)
Pursuant to G.S. 62-133.2 and NCUC Rule	)
R8-55 Relating to Fuel and Fuel-Related	)
Charge Adjustments for Electric Utilities	)

ERIC S. GRANT CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

JUNE 20, 2018

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1173

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**JOSEPH A. MILLER, JR. 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 Joseph A. Miller, Jr. and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

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

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Purdue University with a Bachelor of Science degree in mechanical engineering. I also completed twelve post graduate level courses in Business Administration at Indiana State University. My career began with Duke Energy (d/b/a Public Service of Indiana) in 1991 as a staff engineer at Duke Energy Indiana's Cayuga Steam Station. Since that time, I have held various roles of increasing responsibility in the generation engineering, maintenance, and operations areas, including the role of station manager, first at Duke Energy Kentucky's East Bend Steam Station, followed by Duke Energy Ohio's Zimmer Steam Station. I was named General Manager of Analytical and Investments Engineering in 2010, and became General Manager of Strategic Engineering in 2012 following the merger between Duke Energy and Progress Energy, Inc. I became the Vice President of Central Services in 2014.

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

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

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

A. Yes. I have filed testimony before the North Carolina Utilities Commission ("Commission" or "NCUC") in DEP's 2016 and 2017 annual fuel and fuel-related cost recovery proceedings (Docket Nos. E-2, Subs 1107 and 1146), as well as DEC's 2017 and 2018 annual fuel and fuel-related cost recovery proceedings (Docket Nos. E-7, Subs 1129 and 1163).

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 2017 fuel cost recovery proceeding, as well as those expected in the near term, (2) discuss the performance of DEP's Fossil/Hydro/Solar facilities during the period of April 1, 2017 through March 31, 2018 (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 9,268 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	3,544 MWs
Combustion Turbines -	2,867 MWs
Combined Cycle -	2,568 MWs
Hydro -	227 MWs
Solar[1] -	62 MWs

The 3,544 MWs of coal-fired generation resources represent three generating stations and a total of seven units. These units are equipped with emission control equipment, including selective catalytic reduction ("SCR") equipment for removing nitrogen oxides ("NOx"), flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO2"), and low NOx burners. This inventory of coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content, thereby providing flexibility for DEP to procure the most cost-effective options for fuel supply.

The Company has a total of 33 simple cycle combustion turbine ("CT") units, the larger 14 of which provide 2,183 MWs. These 14 units are located at the

[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.

Asheville (NC), Darlington (SC), Smith Energy (NC), and Wayne County (NC) facilities, and are equipped with water injection and/or low NOx burners for NOx control. The 2,568 MWs shown above as "Combined Cycle " ("CC") represent four power blocks. The HF Lee Energy Complex CC power block ("HF Lee CC") has a configuration of three CTs and one steam turbine. The two power blocks located at the Smith Energy Complex ("Richmond CC") 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 four CC power blocks, are equipped with SCR equipment, and all nine CTs have low NOx burners.

The Company's hydro fleet consists of 15 units providing 227 MWs of capacity and its solar fleet consists of four sites with 141 MWs of nameplate capacity which provide 62 MWs of relative dependable capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEP'S 2017 ANNUAL FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. Sutton CT Unit 1 retired in March 2017, which reduced capacity by 11 MWs. Sutton CT 2A and 2B were retired in July 2017, which reduced capacity by 48 MWs. Corresponding with the retirements, the Company brought online two new fast start CTs at Sutton in July 2017, adding 39 MWs of capacity for each CT for a total of 78 MWs of capacity. Darlington CT Unit 9 retired in June 2017, which reduced capacity by 50 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 Carolinas customers. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with procedures, guidelines, and a standard operating model. Like safety, environmental compliance is a "first principle" and DEP works very hard to achieve high-level results.

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

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

A. For the test period, DEP's total system generation was 62,675,716 MW hours ("MWHs"), of which 33,009,179 MWHs, or approximately 53%, was provided by the Fossil/Hydro/Solar fleet. The breakdown includes 37% contribution from gas facilities, 15% contribution from coal-fired stations, and approximately 1% contribution from hydro and 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 ("JDA"), 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 THE 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 low pricing of natural gas. Further, the addition of CC units within DEP's portfolio 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 69% of the DEP Fossil/Hydro/Solar generation during the test period.

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 WAS THE HEAT RATE FOR DEP'S COAL-FIRED FLEET AND COMBINED CYCLES DURING THE TEST PERIOD?

A. Over the test period, the seven coal units produced 28% of the Fossil/Hydro/Solar generation. The average heat rate for the coal-fired units was 10,737 Btu/kWh. The most active station during this period was Roxboro, providing 72% of the coal production with a heat rate of 10,329 Btu/kWh.

During the test period, the four CC power blocks produced 62% of the Fossil/Hydro/Solar generation with an average heat rate of 7,111 Btu/kWh.

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 test 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 (*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[2] 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 2012 through 2016. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating. The data in the chart reflects DEP results compared to NERC five-year comparisons.

Generator Type	Measure	Review Period	2012-2016	Nbr of Units
		DEP Operational Results	NERC Average	
Coal-Fired Test Period	EAF	78.0%	82.0%	446
	NCF	29.6%	58.3%	
	EFOR	8.0%	7.6%	
Coal-Fired Summer Peak	EAF	90.5%	n/a	n/a
Total CC Average	EAF	85.2%	84.8%	301
	NCF	78.0%	53.0%	
	EFOR	0.69%	5.5%	
Total CT Average	EAF	79.4%	87.6%	826
	SR	98.2%	98.1%	
Hydro	EAF	95.8%	81.1%	1,120

[2] Derated hours are hours the unit operation was less than full capacity.

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 test period to inspect and maintain plant equipment.

Roxboro Unit 4 had a planned outage in Spring 2017. The primary purpose of the outage was to tie-in the new dry bottom ash system. Asheville Unit 1 had a planned outage in Spring 2017 to perform inspections and maintenance on the boiler, SCR, FGD, and air preheaters. Roxboro Units 1-4 had a plant-wide planned outage in Fall 2017. The primary purpose of the outage was to upgrade the FGD control systems and to perform boiler maintenance.

The CC fleet performed planned outages at Richmond County CC PB4 and PB5 in Spring 2017. The primary purpose of the PB4 and PB5 outages was to perform borescope inspections on the combustion turbines and perform balance of plant equipment maintenance.

The CT fleet performed planned outages in Spring and Fall 2017. In Spring 2017 Asheville CT Unit 4 had a planned outage to perform a combustion inspection and to upgrade the controls system. In Fall 2017 Richmond County CT Unit 1 and Darlington Unit 12 and Unit 13 had planned outages. The primary purpose of the Richmond County CT outage was to perform a generator rotor rewind and re-wedge the stator. The outage on Darlington Unit 12 and Unit 13 was to upgrade the protection relay system.

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

A. The Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for NO_x and SO_2 emissions. The SCR technology that DEP currently operates on the coal-fired units uses ammonia or urea for NO_x removal and the scrubber technology employed uses crushed limestone or lime for SO_2 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 NO_x 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 due to competing fuels 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 Ward 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 1173

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 Manager of Nuclear Fuel Engineering's Fuel Management & Design 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 and reload licensing 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.

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 currently serve on 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, 2017 through March 31, 2018 test period ("test period"), and (3) describe changes forthcoming for the December 1, 2018 through November 30, 2019 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 $29.18 per pound for uranium concentrates during the test period, representing a decrease of 26% per pound from the prior test period.

A majority of DEP's enrichment purchases during the test period were delivered under long-term contracts negotiated prior to the test period. The staggered portfolio approach has the effect of mitigating DEP's exposure to price volatility. The average unit cost of DEP's purchases of enrichment services during the test period decreased 39% to $101.85 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 – 15% 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 40% of the total.

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

A. Prices in the uranium concentrate markets remain relatively low due to reduced demand following the March 2011 event at Fukushima. Industry consultants believe that recent production cutbacks have been warranted due to the previously existing oversupply conditions and that market prices need to 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 declined primarily due to reduced demand and increased inventories following the Fukushima event.

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 decrease 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 decrease from 0.686 cents per kWh incurred in the test period, to approximately 0.672 cents per kWh in the billing period. This change reflects the discharge of fuel with a higher cost basis from the reactors and its replacement with fuel procured under new contracts negotiated in lower markets.

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?

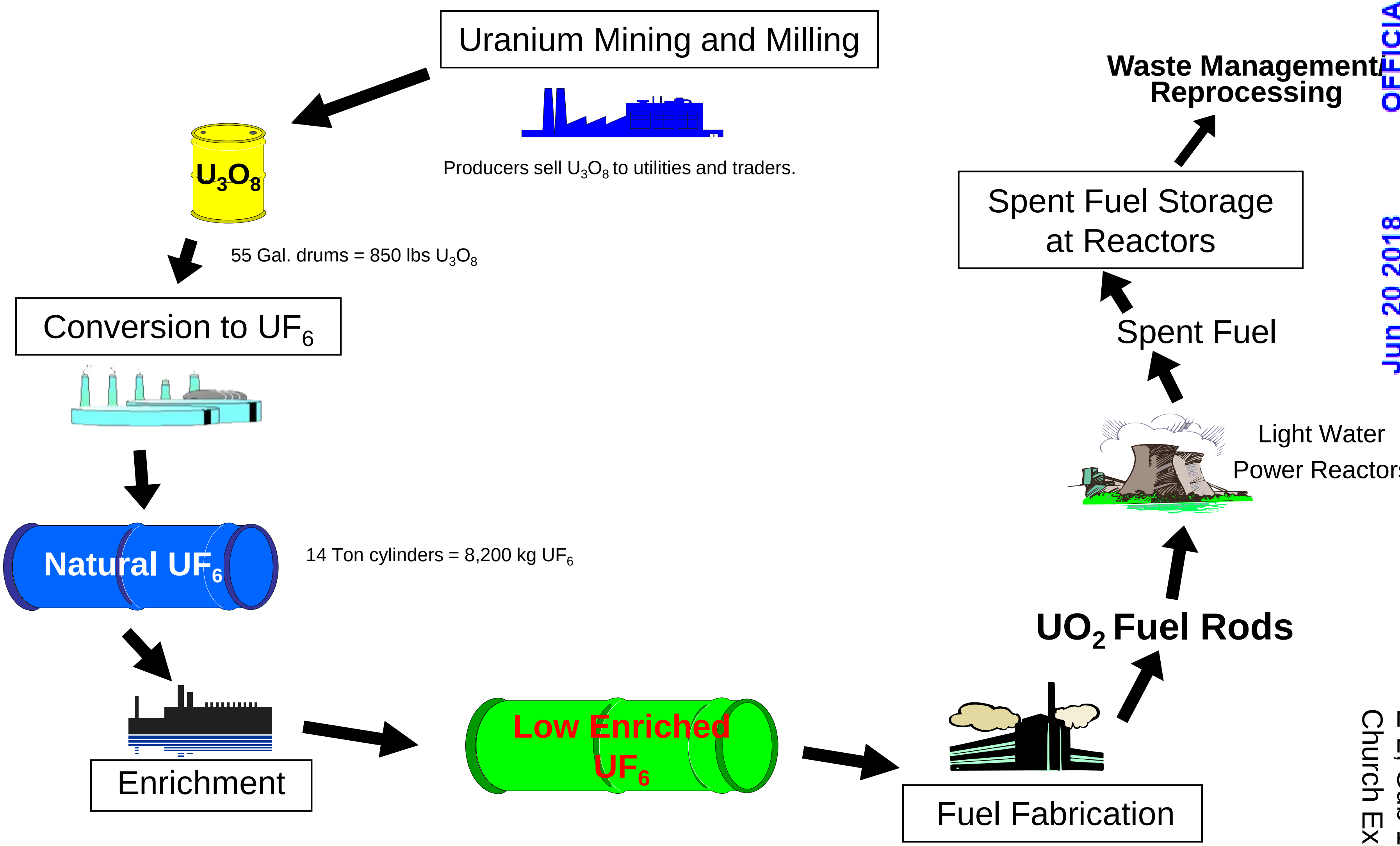
A. As I discussed earlier and as described in Church Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEP relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating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



E-2, Sub 1173
Church Exhibit 2

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 1173

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 PRESENT 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 26 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 OR SUBMITTED TESTIMONY BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. No.

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

A. The purpose of my testimony is to describe and discuss the performance of DEP's nuclear fleet during the period of April 1, 2017 through March 31, 2018 ("test period"). I provide information about refueling outages for the test period and also discuss the nuclear capacity factor being proposed by DEP for use in this proceeding in determining the fuel factor to be reflected in rates during the billing period of December 1, 2018 through November 30, 2019 ("billing period").

Q. PLEASE DESCRIBE EXHIBIT 1 INCLUDED WITH YOUR TESTIMONY.

A. Exhibit 1 is a confidential exhibit outlining the planned schedule for refueling outages for DEP's nuclear units through the billing period. 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 3,543 megawatts ("MWs") of generating capacity, made up as follows:

Brunswick - 1,870 MWs

Harris - 932 MWs[1]

Robinson - 741 MWs

The three generating stations summarized above are comprised of 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 began commercial operation in 1971. The license

[1] MDC was increased effective 1/1/2018.

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 REVIEW PERIOD?

A. Yes. The replacement of the Harris moisture separator reheater ("MSR") in the fall of 2016 increased the efficiency and capacity of the unit. After seasonal observations and validation testing, the Harris maximum dependable capacity ("MDC") was increased by 4 MWs to 932 MWs effective January 1, 2018. The winter capability rating was also increased, adding 7 MWs to the unit's winter capability.

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 47% of the total power generated by DEP. During calendar year 2017, DEP's nuclear fleet recorded the second highest annual net generation in DEP's history, producing just over 29,504 GWHs and falling just below the record established in 2014. Harris set a new net output record during the year, producing just over 8,208 GWHs, which surpassed the prior record established in 2011. The Brunswick station, with annual net generation of just over 15,370 GWHs recorded the second best production in the station's history, falling just below the record established in 2016.

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

A. The Company's nuclear fleet has a history of solid performance that consistently exceeds 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 90.03% for comparable units representing the period 2012 through 2016. The Company's test period capacity factor of 95.67% and 2-year average[2] of 94.66% both exceed the NERC comparable average of 90.03%.

[2] This represents the simple average for the current test period and prior test period of 12 months ended March 2017 for the DEP nuclear fleet.

Industry benchmarking efforts are a principal technique used by the Company to ensure best practices in operations. Duke Energy's nuclear fleet continues to rank among the top performers when compared to the seven other large domestic nuclear fleets using Key Performance Indicators ("KPIs") in the areas of personal safety, radiological dose, manual and automatic shutdowns, capacity factor, forced loss rate, industry performance index, and total operating cost. By continually assessing the Company's performance as compared with industry benchmarks, the Company continues to ensure the overall safety, reliability and cost-effectiveness of DEP's nuclear units.

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

A. In general, refueling, maintenance, and NRC required testing and inspections impact the availability of DEP's nuclear system.

Prior to a planned outage, DEP develops a detailed schedule for the outage and for major tasks to be performed, including sub-schedules for particular activities. The Company's scheduling philosophy is to strive for the best possible outcome for each outage activity within the outage plan. For example, if the "best ever" time an outage task was performed is 10 days, then 10 days or less becomes the goal for that task in each subsequent outage. Those individual aspirational goals are incorporated into an overall outage schedule. The Company then aggressively works to meet, and measures itself against, that aspirational schedule. To minimize potential impacts to outage schedules due to unforeseen maintenance requirements, "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.

As noted, the schedule is utilized for measuring outage planning and execution and driving continuous improvement efforts. However, for planning purposes, particularly with the dispatch and system operating center functions, DEP also develops an allocation of outage time that 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. If an unanticipated issue that has the potential to become an on-line reliability challenge 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 extended when in the best interest of customers to perform necessary maintenance or repairs prior to returning the unit to service. The decision to extend an outage or to defer work is based on numerous factors, including reliability risk assessments, system power demands, and the availability of resources to address the emergent challenge. In general, if an issue poses a credible risk to reliable operations until the next scheduled outage, the issue is repaired prior to returning the unit to service. This approach enhances reliability and results in longer continuous run times and fewer forced outages, thereby reducing fuel costs for customers in the long run. 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 self-critical observation for 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 OUTAGES WERE REQUIRED FOR REFUELING AT DEP'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. There were two refueling outages completed during the test period.[3]

Brunswick Unit 2 began a refueling outage on March 17, 2017. In addition to refueling and maintenance activities, safety and reliability enhancements were completed. Work on the emergency diesel generator number 4 included replacement of the governor and timing relays, and installation of an automatic voltage regulator and jet air assist system. Switchyard reliability improvements included open phase relay protection modifications to both the start-up ("SAT") and unit auxiliary transformers ("UAT"). Inspections and repairs were completed on the 'A' and 'B' low pressure turbines and a main generator exciter water cooled diode bridge modification was completed. Fukushima related modifications included the installation of a harden containment vent on Unit 2, and the installation of fire hose pressure reducing valves. Ten year interval in-service ("ISI") and non-destructive evaluations ("NDE") testing were completed. During startup activities, turbine vibrations extended the outage by 1.8 days above allocation. After the turbine issues were corrected, the unit returned to service on April 17, 2017. On April 18, 2017, the unit was removed from service for just under two hours to complete turbine overspeed testing.

Brunswick Unit 1 was removed from the grid for refueling on March 3, 2018. In addition to refueling, safety, reliability, and regulatory enhancements

[3] The Brunswick Unit 1 refueling outage began on March 3, 2018 and ended on April 4, 2018, 4 days beyond the end of the test period.

and projects were completed. Emergency Diesel Generator ("EDG") modifications were completed on EGD 2, including upgrades to starting air system, automatic voltage regulator, and governor. Completion of these safety and reliability enhancements on EDG 2 marks the completion of this safety and reliability enhancement project on all 4 of the station's EDGs. Regulatory work accomplished included the completion of all modifications associated with National Fire Protection Association ("NFPA") 805 requirements and post-Fukushima required Harden Wetwell Vent installation. Turbine related work included the implementation of the digital turbine pressure control, turbine vibration system and valve hydraulic operating components. A full turbine alignment and balance shot was also completed. After refueling, projects, maintenance, and inspections were completed, the unit returned to service on April 4, 2018. The outage was completed in 32.48 days compared to a 35 day allocation. Following the end of the refueling outage, the turbine was disconnected from the grid for just over 2 hours to complete overspeed testing.

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 94.12% 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 Ward and exceeds the five-year industry weighted average capacity factor of 90.03% for comparable units as reported in the NERC Brochure during the period of 2012 to 2016.

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

A. Yes, it does.

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's Fuel Charge Adjustment Proceeding, in Docket No. E-2, Sub 1173, 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 20th day of June, 2018.

/s/ Dwight W. Allen

Dwight W. Allen
Allen Law Offices, PLLC
1514 Glenwood Avenue, Suite 200
Raleigh, North Carolina 27608
Tel: (919) 838-0529
dallen@theallenlawoffices.com
North Carolina State Bar No. 5484

ATTORNEY FOR DUKE ENERGY PROGRESS, LLC