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June 21, 2017

VIA ELECTRONIC FILING AND OVERNIGHT 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 1146
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 an original and 15 copies of 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 Brett Phipps, Joseph A. Miller, Jr., T. Preston Gillespie, Jr., and Kenneth D. Church containing the information required in NCUC Rule R8-55.

Information contained in Mr. Gillespie's Exhibit 1 is confidential because it contains sensitive information regarding DEP's future nuclear outage schedule. Information contained in Mr. Phipps'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. Therefore, enclosed is the original plus 15 copies filed under seal pursuant to N.C. Gen. Stat. § 62-132.11, and one original plus one copy with the confidential information redacted. These confidential documents 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,

Robert W. Kaylor

Robert W. Kaylor

Enclosures
cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1146

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 1771
Raleigh, North Carolina 27602

2. The names and addresses of Applicant's attorneys are:

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

3. NCUC Rule R8-55 provides that the Commission shall schedule annual hearings pursuant to N.C. Gen. Stat. § 62-133.2 in order to review changes in the cost of fuel and fuel-related costs since the last general rate case for each utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service. Rule R8-55 schedules an annual cost of fuel and fuel-related costs adjustment hearing for DEP and requires that the Company use a test period of 12 months ended March 31. Therefore, the test period used in this Application for these proceedings is April 1, 2016 – March 31, 2017 ("test period").

4. In Docket No. E-2, Sub 1107, 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	1.993¢ per kWh
Small General Service	2.088¢ per kWh
Medium General Service	2.431¢ per kWh
Large General Service	2.253¢ per kWh
Lighting	0.596¢ per kWh

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

Residential	2.051¢ per kWh
Small General Service	1.976¢ per kWh
Medium General Service	2.251¢ per kWh
Large General Service	2.350¢ per kWh
Lighting	1.368¢ per kWh

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

Residential	0.000¢ per kWh
Small General Service	0.000¢ per kWh
Medium General Service	(0.081)¢ per kWh
Large General Service	0.000¢ per kWh
Lighting	0.000¢ per kWh

The base fuel and fuel-related costs factors should also be adjusted for the EMF interest (decrement) (excluding regulatory fee) of:

Residential	0.000¢ per kWh
Small General Service	0.000)¢ per kWh
Medium General Service	(0.014)¢ per kWh
Large General Service	0.000¢ per kWh
Lighting	0.000¢ per kWh

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

Residential	2.051¢ per kWh
Small General Service	1.976¢ per kWh
Medium General Service	2.156¢ per kWh
Large General Service	2.350¢ per kWh
Lighting	1.368¢ per kWh

The new fuel factors should become effective for service on or after December 1, 2017.

6. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Brett Phipps, Joseph A. Miller, Jr., T. Preston Gillespie, Jr., 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.

7. For comparison, in accordance with Rule R8-55(d)(1) and R8-55(e)(3), base fuel and fuel-related costs factors were also calculated based on the most recent North American Electric Reliability Corporation ("NERC") five-year national average nuclear capacity factor (88.9%) 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	2.107¢ per kWh	2.045¢ per kWh
Small General Service	2.039¢ per kWh	1.960¢ per kWh
Medium General Service	2.200¢ per kWh	2.142¢ per kWh
Large General Service	2.379¢ per kWh	2.360¢ per kWh
Lighting	1.494¢ per kWh	1.381¢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	2.051¢ per kWh
Small General Service	1.976¢ per kWh
Medium General Service	2.156¢ per kWh
Large General Service	2.350¢ per kWh
Lighting	1.368¢ per kWh

Respectfully submitted this 21nd day of June, 2017.

By: ______________________________

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ATTORNEYS FOR DUKE ENERGY PROGRESS, LLC

STATE OF NORTH CAROLINA)
) VERIFICATION
COUNTY OF MECKLENBURG)

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

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

Kendra A. Ward

Kendra A. Ward

Sworn to and subscribed before
me this 21nd day of June, 2017.

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

Notary Public

My Commission expires: 7-31-17

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1146

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 as a staff auditor. From 2006 until 2013 I held various financial accounting and reporting roles at Cherry, Bekaert and Holland, 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. No.

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 6, along with supporting workpapers. The test period used in supplying this information and data is the period April 1, 2016 through March 31, 2017 ("test period"), and the billing period is December 1, 2017 through November 30, 2018 ("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 6 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

92.6% proposed nuclear capacity factor and projected billing period megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 92.6% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting an 88.9% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for pressurized water reactors 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: March 2017 Monthly Fuel Reports.

1) March 2017 Monthly Fuel Report required by NCUC Rule R8-52.

2) March 2017 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

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.

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 92.6% nuclear capacity factor as testified to by Company witness Gillespie, projected fossil fuel costs as testified to by Company witness Phipps, 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	2.051	1.976	2.251	2.350	1.368
EMF Increment/(Decrement) cents/kWh	-	-	(0.081)	-	-
EMF Interest Decrement cents/kWh	-	-	(0.014)	-	-
Net Fuel and Fuel Related Costs Factors cents/kWh	2.051	1.976	2.156	2.350	1.368

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 2.2% 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	2.051	1.976	2.156	2.350	1.368
Current Factors cents/kWh	1.833	1.729	1.984	2.237	0.876

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

A. The largest component of the increase is the incorporation of the return of $10.6 million of over-collected fuel costs and interest related to the test period EMF decrement, in contrast to the $82 million of over-collected fuel costs and interest included in the existing EMF decrement. In addition, total fuel costs projected for the billing period are slightly decreasing. Although commodity prices are increasing, greater availability of nuclear and gas generation results in an overall decrease in system fuel costs.

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 92.6% as explained by Company witness Gillespie 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 92.6% 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 88.9%. This capacity factor is based on the 2011 through 2015 data reported in the NERC's Generating Unit Statistical Brochure ("NERC Brochure") for pressurized water reactors rated at or above 800 MWs. 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 and cogeneration power 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 88.9% NERC nuclear capacity factor compared to the proposed 92.6% nuclear capacity factor.

Q. WARD EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD OVER/(UNDER) RECOVERY BALANCE AND THE EMF RATE. HOW DID 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 $33 million for the combined customer classes. The table below shows the breakdown by customer class.

	Residential	Small General Service	Medium General Service	Large General Service	Lighting
	cents/KWh	cents/KWh	cents/KWh	cents/KWh	cents/KWh
EMF over/ (under) Collection of Fuel - ($ million)	$ (21.7)	$ (1.1)	$ 9.1	$ (17.9)	$ (1.8)
EMF Interest Costs ($ million)	$ -	$ -	$ 1.5	$ -	$ -

The 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.

Q. WHAT IS DEP'S PROPOSAL WITH RESPECT TO THE OVER/(UNDER) RECOVERY BALANCE?

A. DEP proposes to defer collection of the $42.5 million under- recovered amounts for the residential, small general service, large general service and lighting classes until its 2018 annual fuel proceeding, in order to mitigate customer rate impacts. Deferring the recovery of the under-collection balance to next year reduces the current year proposed residential percentage increase from 3.4% to 2.1% and reduces the typical residential customer's monthly bill increase from $3.52 to $2.18. DEP will return the over-recovered amount of $9.1 million plus interest to the medium general service class during the rate period December 1, 2017 through November 30, 2018.

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 1023) and fuel and fuel-related cost recovery proceeding (Docket No. E-2, Sub 1107). 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. DO YOU BELIEVE DEP'S FUEL AND FUEL-RELATED COSTS INCURRED IN THE TEST YEAR ARE REASONABLE?

A. Yes. As shown on Ward Exhibit 6, DEP's test year actual fuel and fuel-related costs were 2.441 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 Gillespie 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 Phipps 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 are allocated in compliance with N.C. Gen. Stat. § 62-133.2(a2). These costs are described in subdivisions (4), (5), and (6) of N.C. Gen. Stat. § 62-133.2(a1). Subdivision (4) includes purchased power non-capacity costs subject to economic curtailment or dispatch. Subdivision (5) includes cogeneration and independent power producer capacity costs. Subdivision (6) includes renewable capacity costs. The allocation methods for subdivisions (4), (5), and (6) are found in paragraph 26 of DEP's last general rate case Order in Docket No. E-2, Sub 1023. Capacity-related purchased power costs in Subdivision (5) and (6) 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 1023. Subdivision (4) costs and non-capacity costs in Subdivision (6) 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 2016 fuel and fuel-related cost recovery proceeding in Docket No. E-2, Sub 1107.

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 2.2% was calculated by dividing the fuel and fuel-related cost increase of $69 million for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $3.2 billion. The cost increase of $69 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. Net gains or losses related to the sale of by-products for beneficial reuse from the Sutton coal plant are being handled in accordance with witness McGee's testimony in the DEP rate case, Docket E-2, Sub 1142, and are not included in the proposed fuel rates.

Q. CAN YOU IDENTIFY WHERE IN THIS FILING THE MERGER FUEL RELATED SAVINGS ARE INCLUDED?

A. Merger fuel-related savings automatically flow to DEP's retail customers through the fuel and fuel-related cost component of customers' rates. Actual merger savings during the test period are included in the EMF portion of the proposed fuel and fuel-related cost factors. In addition, in the prospective component of the factors, the projected merger savings related to procuring coal and reagents, lower transportation costs, lower gas capacity costs, and coal blending are reflected in the cost of fossil fuel. Projected joint dispatch savings, which are the result of using the combined systems' lowest available generation to meet total customer demand, are also reflected in the cost of fossil fuel as well as the projected purchases and sales that include the purchases and sales between DEP and DEC. Actual and projected savings related to the procurement of nuclear fuel are reflected in the cost of nuclear fuel.

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, 2017
Billing Period December 1, 2017 - November 30, 2018
Docket E-2, Sub 1146

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 1107)						
1	Approved Fuel and Fuel Related Costs Factors	Input	1.993	2.088	2.431	2.253	0.596
2	EMF Increment / (Decrement)	Input	(0.137)	(0.308)	(0.383)	(0.014)	0.280
3	EMF Interest Decrement cents/kWh	Input	(0.023)	(0.051)	(0.064)	(0.002)	-
4	Approved Net Fuel and Fuel Related Costs Factors	Sum	1.833	1.729	1.984	2.237	0.876
	Fuel and Fuel Related Cost Factors						
5	NERC Capacity Factor of 88.9% with Projected Sales	Exh 2 Sch 3 pg 3	2.107	2.039	2.200	2.379	1.494
6	Proposed Nuclear Capacity Factor of 92.6% and Normalized Test Period Sales	Exh 2 Sch 2 pg 3	2.045	1.960	2.142	2.360	1.381
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 92.6%						
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	1.993	1.910	2.198	2.317	1.368
8	Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.058	0.066	0.053	0.033	0.000
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	2.051	1.976	2.251	2.350	1.368
10	EMF Increment/(Decrement) cents/kWh	Exh 2 Sch 1 pg 2	-	-	(0.081)	-	-
11	EMF Interest Decrement cents/kWh	Exh 2 Sch 1 pg 2	-	-	(0.014)	-	-
12	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 pg 2	2.051	1.976	2.156	2.350	1.368

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 92.6%
Twelve Months December 2017 - November 2018
Docket E-2, Sub 1146

Line No.	Unit	Reference	Generation (MWH)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 3-4	28,721,189	0.7137	$ 204,976,825
2	Coal	Workpaper 3 - 4	9,784,920	3.2327	316,313,648
3	Gas - CT and CC	Workpaper 3 - 4	20,231,727	2.8710	580,845,112
4	Reagents & By Products	Workpaper 12	-		23,900,904
5	Total Fossil	Sum of Lines 2 - 4	30,016,647		921,059,663
6	Hydro	Workpaper 3	598,023		
7	Net Pumped Storage		-		
8	Total Hydro	Sum of Lines 6 - 7	598,023		
9	Utility Owned Solar Generation	Workpaper 3	282,714		
10	Total Generation	Line 1 + Line 5 + Line 8 + line 9	59,618,574		1,126,036,488
11	Purchases	Workpaper 3 - 4	8,404,277		289,435,336
12	JDA Savings Shared	Workpaper 5	-		(1,894,189)
13	Total Purchases	Sum of Lines 11 - 12	8,404,277		287,541,147
14	Total Generation and Purchases	Line 10 + Line 13	68,022,851		1,413,577,635
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(3,109,193)		(79,089,672)
16	Line losses and Company use	Line 19 - Line 15 - Line 14	(2,749,842)		-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16			$ 1,334,487,963
18	Projected System MWh Sales for Fuel Factor	Workpaper 3	62,163,816		62,163,816
19	Fuel and Fuel Related Costs cents/kWh	Line 17 /Line 18 / 10			2.147

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 92.6%
Twelve Months December 2017 - November 2018
Docket E-2, Sub 1146

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	15,667,933	1,808,399	10,417,309	9,237,571	395,287	37,526,498
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power - Capacity	Workpaper 4						$ 31,684,006
3	Cogeneration Purchased Power - Capacity							0
4	Total of Renewable and Cogeneration Purchased Power Capacity	Line 2 + Line 3						$ 31,684,006
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input						59.73%
6	NC Renewable and Cogeneration Purchased Power Capacity	Line 4 * Line 5						$ 18,925,807
7	Production Plant Allocation Factors	Input	48.271%	6.307%	29.139%	16.275%	0.009%	100.000%
8	Renewable Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 9,135,586	$ 1,193,561	$ 5,514,842	$ 3,080,152	$ 1,666	$ 18,925,807
9	Renewable Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.058	0.066	0.053	0.033	-	0.050
	Summary of Total Rate by Class							
10	Fuel and Fuel Related Costs excluding Renewable Purchased Power and Cogeneration Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	1.993	1.910	2.198	2.317	1.368	
11	Purchased Power - Capacity cents/kWh	Line 9	0.058	0.066	0.053	0.033	-	
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.051	1.976	2.251	2.350	1.368	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	(0.081)	-	-	
14	EMF Interest Decrement cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	(0.014)	-	-	
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	2.051	1.976	2.156	2.350	1.368	

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 92.6%
Twelve Months December 2017 - November 2018
Docket E-2, Sub 1146

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 1107 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 25 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	15,667,933	$ 1,566,293,890	$ 34,186,981	2.2%	0.218	1.833	2.051
2	Small General Service	1,808,399	$ 204,814,740	$ 4,470,424	2.2%	0.247	1.729	1.976
3	Medium General Service	10,417,309	$ 822,901,121	$ 17,961,192	2.2%	0.172	1.984	2.156
4	Large General Service	9,237,571	$ 480,324,787	$ 10,483,891	2.2%	0.113	2.237	2.350
5	Lighting	395,287	$ 89,169,269	$ 1,946,268	2.2%	0.492	0.876	1.368
6	NC Retail	37,526,498	$ 3,163,503,807	$ 69,048,756				

Line No.			
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 7	$ 1,335,145,078
8	System Renewable and Cogeneration Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	31,684,006
9	Adjusted System Other Fuel Costs	Line 7 - Line 8	$ 1,303,461,072
10	NC Retail Allocation % - sales at generation	Workpaper 8	60.89%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 793,677,447
12	NC Renewable and Cogeneration Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	18,925,807
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 812,603,254
14	NC Projected Billing Period MWH Sales	Line 6, col A	37,526,498
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	2.165
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	(0.024)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	(0.004)
18	Total Proposed Composite Fuel Rate	Sum of Lines 15-17	2.137
	Total Current Composite Fuel Rate - Docket E-2 Sub 1107:		
19	Current composite Fuel Rate cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3	2.172
20	Current composite EMF Rate cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3	(0.187)
21	Current composite EMF Interest cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3	(0.032)
22	Total Current Composite Fuel Rate	Sum of Lines 19-21	1.953
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.184
24	NC Projected Billing Period MWH Sales	Line 6, col A	37,526,498
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 69,048,756

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 92.6% and Normalized Test Period Sales
Billing Period December 1, 2017 - November 30, 2018
Docket E-2, Sub 1146

Line No.	Unit	Reference	Generation (MWH)	Unit Cost (cents/KWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 3-4	28,721,189	0.7137	$	204,976,825
2	Coal	Calculated	9,546,228	3.2327		308,597,536
3	Gas - CT and CC	Workpaper 3-4	20,231,727	2.8710		580,845,112
4	Reagents & By Products	Workpaper 4	-			23,900,904
5	Total Fossil	Sum of Lines 2 - 4	29,777,955			913,343,551
6	Hydro	Workpaper 3	598,023			
7	Net Pumped Storage		-			
8	Total Hydro	Sum of Lines 6 - 7	598,023			
9	Utility Owned Solar Generation	Workpaper 3	282,714			
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	59,379,882			1,118,320,376
11	Purchases	Workpaper 3 - 4	8,404,277			289,435,336
12	JDA Savings Shared	Workpaper 5	-			(1,894,189)
13	Total Purchases	Sum of Lines 11 - 12	8,404,277			287,541,147
14	Total Generation and Purchases	Line 10 + Line 13	67,784,159			1,405,861,523
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(3,109,193)			(79,089,672)
16	Line losses and Company use	Line 19 - Line 15 - Line 14	(2,739,318)			-
17	System Fuel Expense for Fuel Factor	Lines 14 + Line 15 + Line 16			$	1,326,771,851
18	Normalized Test Period MWh Sales for Fuel Factor	Exhibit 4	61,935,648			61,935,648
19	Fuel and Fuel Related Costs cents/kWh	Line 17 / Line 18 / 10				2.142

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 92.6% and Normalized Test Period Sales
Billing Period December 1, 2017 - November 30, 2018
Docket E-2, Sub 1146

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	15,786,375	1,896,757	11,162,395	8,347,370	377,137	37,570,033
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power - Capacity	Workpaper 4						$ 31,684,006
3	Cogeneration Purchased Power - Capacity							0
4	Total of Renewable and Cogeneration Purchased Power Capacity	Line 2 + Line 3						$ 31,684,006
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input						59.73%
6	NC Renewable and Cogeneration Purchased Power Capacity	Line 4 * Line 5						$ 18,925,807
7	Production Plant Allocation Factors	Input	48.271%	6.307%	29.139%	16.275%	0.009%	100.000%
8	Renewable Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 9,135,586	$ 1,193,561	$ 5,514,842	$ 3,080,152	$ 1,666	$ 18,925,807
9	Renewable Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.058	0.063	0.049	0.037	-	0.050
	Summary of Total Rate by Class							
10	Fuel and Fuel Related Costs excluding Renewable Purchased Power and Cogeneration Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	1.987	1.897	2.188	2.323	1.381	
11	Purchased Power - Capacity cents/kWh	Line 9	0.058	0.063	0.049	0.037	-	
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.045	1.960	2.237	2.360	1.381	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	(0.081)	-	-	
14	EMF Interest Decrement cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	(0.014)	-	-	
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	2.045	1.960	2.142	2.360	1.381	

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 92.6% and Normalized Test Period Sales
Billing Period December 1, 2017 - November 30, 2018
Docket E-2, Sub 1146

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 1069 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 25 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	15,786,375	$ 1,566,293,890	$ 33,482,585	2.1%	0.212	1.833	2.045
2	Small General Service	1,896,757	$ 204,814,740	$ 4,378,314	2.1%	0.231	1.729	1.960
3	Medium General Service	11,162,395	$ 822,901,121	$ 17,591,115	2.1%	0.158	1.984	2.142
4	Large General Service	8,347,370	$ 480,324,787	$ 10,267,879	2.1%	0.123	2.237	2.360
5	Lighting	377,137	$ 89,169,269	$ 1,906,167	2.1%	0.505	0.876	1.381
6	NC Retail	37,570,033	$ 3,163,503,807	$ 67,626,060				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 7a	$ 1,327,428,966
8	System Renewable and Cogeneration Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	31,684,006
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,295,744,960
10	NC Retail Allocation % - sales at generation	Workpaper 8	61.19%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 792,866,341
12	NC Renewable and Cogeneration Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	18,925,807
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 811,792,148
14	Adjusted NC Normalized Period MWH Sales	Line 6, col A	37,570,033
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 /10	2.161
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	(0.024)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	(0.004)
18	Total Proposed Composite Fuel Rate	Sum of Lines 15-17	2.133
	Total Current Composite Fuel Rate - Docket E-2 Sub 1107:		
19	Current composite Fuel Rate cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3	2.172
20	Current composite EMF Rate cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3	(0.187)
21	Current composite EMF Interest cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3	(0.032)
22	Total Current Composite Fuel Rate	Sum of Lines 19 - 21	1.953
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.180
24	Adjusted NC Normalized Period MWH Sales	Line 6, col A	37,570,033
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 67,626,060

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 88.9% with Projected Sales
Billing Period December 1, 2017 - November 30, 2018
Docket E-2, Sub 1146

Line No.	Unit	Reference	Generation (MWH)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 2	27,571,494	0.7137	$ 196,771,701
2	Coal	Calculated	10,934,615	3.2327	353,479,437
3	Gas - CT and CC	Workpaper 3 - 4	20,231,727	2.8710	580,845,112
4	Reagents & By Products	Workpaper 4	-		23,900,904
5	Total Fossil	Sum of Lines 2 - 4	31,166,342		958,225,452
6	Hydro	Workpaper 3	598,023		
7	Net Pumped Storage		-		
8	Total Hydro	Sum of Lines 6 - 7	598,023		
9	Utility Owned Solar Generation	Workpaper 3	282,714		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	59,618,573		1,154,997,153
11	Purchases	Workpaper 3 - 4	8,404,277		289,435,336
12	JDA Savings Shared	Workpaper 5	-		(1,894,189)
13	Total Purchases	Sum of Lines 11- 12	8,404,277		287,541,147
14	Total Generation and Purchases	Line 10 + Line 13	68,022,850		1,442,538,300
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(3,109,193)		(79,089,672)
16	Line losses and Company use	Line 19 - Line 15 - Line 14	(2,749,841)		-
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16			$ 1,363,448,628
18	System MWh Sales for Fuel Factor	Workpaper 3	62,163,816		62,163,816
19	Fuel and Fuel Related Costs cents/kWh	Line 17 / Line 18 / 10			2.193

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 88.9% with Projected Sales
Billing Period December 1, 2017 - November 30, 2018
Docket E-2, Sub 1146

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	15,667,933	1,808,399	10,417,309	9,237,571	395,287	37,526,498
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power - Capacity	Workpaper 4						$ 31,684,006
3	Cogeneration Purchased Power - Capacity							0
4	Total of Renewable and Cogeneration Purchased Power Capacity	Line 2 + Line 3						$ 31,684,006
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input						59.73%
6	NC Renewable and Cogeneration Purchased Power Capacity	Line 4 * Line 5						$ 18,925,807
7	Production Plant Allocation Factors	Input	48.271%	6.307%	29.139%	16.275%	0.009%	100.000%
8	Renewable Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 9,135,586	$ 1,193,561	$ 5,514,842	$ 3,080,152	$ 1,666	$ 18,925,807
9	Renewable Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.058	0.066	0.053	0.033	0.000	0.050
	Summary of Total Rate by Class							
10	Fuel and Fuel Related Costs excluding Renewable Purchased Power and Cogeneration Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.049	1.973	2.242	2.346	1.494	
11	Purchased Power - Capacity cents/kWh	Line 9	0.058	0.066	0.053	0.033	0.000	
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.107	2.039	2.295	2.379	1.494	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	(0.081)	-	-	
14	EMF Interest Decrement cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	(0.014)	-	-	
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	2.107	2.039	2.200	2.379	1.494	

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 88.9% with Projected Sales
Billing Period December 1, 2017 - November 30, 2018
Docket E-2, Sub 1146

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 1069 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 25 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	15,667,933	$	1,566,293,890	$	42,919,525	2.7%	0.274	1.833	2.107
2	Small General Service	1,808,399	$	204,814,740	$	5,612,326	2.7%	0.310	1.729	2.039
3	Medium General Service	10,417,309	$	822,901,121	$	22,549,105	2.7%	0.216	1.984	2.200
4	Large General Service	9,237,571	$	480,324,787	$	13,161,841	2.7%	0.142	2.237	2.379
5	Lighting	395,287	$	89,169,269	$	2,443,413	2.7%	0.618	0.876	1.494
6	NC Retail	37,526,498	$	3,163,503,807	$	86,686,210				

Line No.	Description	Source		Amount
	Total Proposed Composite Fuel Rate:			
7	Adjusted System Total Fuel Costs	Workpaper 7b	$	1,364,105,743
8	System Renewable and Cogeneration Purchased Power Capacity	Exhibit 2 Sch 3, Page 2		31,684,006
9	System Other Fuel Costs	Line 7 - Line 8	$	1,332,421,737
10	NC Retail Allocation % - sales at generation	Workpaper 8		60.89%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$	811,311,596
12	NC Renewable and Cogeneration Purchased Power Capacity	Exhibit 2 Sch 3, Page 2		18,925,807
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$	830,237,403
14	NC Projected Billing Period MWH Sales	Line 6, col A		37,526,498
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 /10		2.212
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		(0.024)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1		(0.004)
18	Total Proposed Composite Fuel Rate	Sum of Lines 15-17		2.184
	Total Current Composite Fuel Rate - Docket E-2 Sub 1107:			
19	Current composite Fuel Rate cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3		2.172
20	Current composite EMF Rate cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3		(0.187)
21	Current composite EMF Interest cents/kWh	Revised McGee Exhibit 2, Sch. 1, Pg 3		(0.032)
22	Total Current Composite Fuel Rate	Sum of Lines 19 - 21		1.953
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22		0.231
24	NC Projected Billing Period MWH Sales	Line 6, col A		37,526,498
25	Increase/(Decrease) in Fuel Costs	Line 23* Line 24 * 10	$	86,686,210

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, 2017
Docket E-2, Sub 1146

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 2016 (Sub 1069)			2,600,935	$ 10,069,491	-	$ 10,069,491
2	May			2,623,855	2,922,867	-	2,922,867
3	June			3,150,543	(3,195,111)	-	(3,195,111)
4	July			3,546,318	(14,204,192)	-	(14,204,192)
5	August			3,921,804	(6,364,676)	-	(6,364,676)
6	September			3,608,732	951,826	-	951,826
7	October			2,862,106	(176,810)	-	(176,810)
8	November			2,581,057	2,493,779	-	2,493,779
9	December (1) (New Rates - Sub 1107)			2,873,976	(10,213,615)	-	(10,213,615)
10	January 2017			3,449,952	(2,942,213)	-	(2,942,213)
11	February			2,858,255	2,290,030	-	2,290,030
12	March			2,843,639	(15,029,118)	-	(15,029,118)
13	Total Test Period			36,921,171	$ (33,397,742)	$ -	$ (33,397,742)
14	Less: Proposed (under) collection deferral						42,483,532
15	Booked Over Recovery April 2016 to March 2017						$ 9,085,790
16	Normalized Test Period MWH Sales	Exhibit 4					37,570,033
17	Experience Modification Increment / (Decrement) cents/KWh						(0.024)
18	Interest						$ 1,514,298
19	EMF Interest Decrement						(0.004)

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, 2017
Docket E-2, Sub 1146

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 2016 (Sub 1069)		2.346	2.450	956,300	$ 989,962		$ 989,962
2	May		2.730	2.450	942,463	(2,639,367)		(2,639,367)
3	June		2.695	2.450	1,253,280	(3,066,524)		(3,066,524)
4	July		2.796	2.450	1,525,470	(5,283,467)		(5,283,467)
5	August		2.509	2.450	1,720,332	(1,010,695)		(1,010,695)
6	September		2.461	2.450	1,495,082	(171,336)		(171,336)
7	October		2.904	2.450	1,014,698	(4,602,060)		(4,602,060)
8	November		2.705	2.450	939,368	(2,392,665)		(2,392,665)
9	December (1) (New Rates - Sub 1107)		2.427	2.266	1,271,814	(2,616,780)		(2,616,780)
10	January 2017		1.825	2.030	1,652,408	3,385,022		3,385,022
11	February		1.867	1.993	1,227,196	1,542,586		1,542,586
12	March		2.481	1.993	1,189,431	(5,801,925)		(5,801,925)
13	Total Test Period				15,187,842	$ (21,667,250)	$ -	$ (21,667,250)
14	Less: Proposed (under) collection deferral							21,667,250
15	Booked Over Recovery April 2016 to March 2017							$ -
16	Normalized Test Period MWH Sales	Exhibit 4						15,786,375
17	Experience Modification Increment (Decrement) cents/KWh							-
18	Annual Interest Rate							10%
19	Monthly Interest Rate							0.83333%
20	Number of Months (October 2016 - May 2018)							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, 2017
Docket E-2, Sub 1146

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 2016 (Sub 1069)	2.130	2.433	127,657	$ 387,235		$ 387,235
2	May	2.333	2.433	133,424	133,103		133,103
3	June	2.502	2.433	162,989	(111,794)		(111,794)
4	July	2.738	2.433	188,465	(575,553)		(575,553)
5	August	2.520	2.433	206,951	(179,944)		(179,944)
6	September	2.279	2.433	195,485	301,985		301,985
7	October	2.419	2.433	147,111	21,331		21,331
8	November	2.388	2.433	128,330	58,095		58,095
9	December (1) (New Rates - Sub 1107)	2.709	2.294	137,561	(639,263)		(639,263)
10	January 2017	2.122	2.116	171,104	(11,208)		(11,208)
11	February	1.925	2.088	143,708	234,876		234,876
12	March	2.589	2.088	137,528	(688,960)		(688,960)
13	Total Test Period			1,880,312	$ (1,070,097)	$ -	$ (1,070,097)
14	Less: Proposed (under) collection deferral						1,070,097
15	Booked Over Recovery April 2016 to March 2017						$ -
16	Normalized Test Period MWH Sales	Exhibit 4					1,896,757
17	Experience Modification Increment (Decrement) cents/KWh						-
18	Annual Interest Rate						10%
19	Monthly Interest Rate						0.83333%
20	Number of Months (October 2016 - May 2018)						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, 2017
Docket E-2, Sub 1146

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 2016 (Sub 1069)		1.798	2.433	830,252	$ 5,272,601		$ 5,272,601
2	May		1.958	2.433	874,335	4,154,226		4,154,226
3	June		2.291	2.433	981,137	1,397,531		1,397,531
4	July		2.704	2.433	1,049,724	(2,841,078)		(2,841,078)
5	August		2.489	2.433	1,153,731	(647,474)		(647,474)
6	September		2.222	2.433	1,101,799	2,323,363		2,323,363
7	October		2.079	2.433	943,065	3,339,580		3,339,580
8	November		2.063	2.433	819,586	3,031,566		3,031,566
9	December (1) (New Rates - Sub 1107)		2.744	2.432	809,499	(2,894,712)		(2,894,712)
10	January 2017		2.607	2.431	922,582	(1,618,378)		(1,618,378)
11	February		2.312	2.431	800,779	955,169		955,169
12	March		2.833	2.431	841,518	(3,386,606)		(3,386,606)
13	Total Test Period				11,128,006	$ 9,085,789	$ -	$ 9,085,789
14	Less: Proposed (under) collection deferral							-
15	Booked Over Recovery April 2016 to March 2017							$ 9,085,789
16	Normalized Test Period MWH Sales	Exhibit 4						11,162,395
17	Experience Modification Increment (Decrement) cents/KWh							(0.081)
18	Annual Interest Rate							10%
19	Monthly Interest Rate							0.83333%
20	Number of Months (October 2016 - May 2018)							20
21	Interest							$ 1,514,298
22	EMF Interest Decrement							(0.014)

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, 2017
Docket E-2, Sub 1146

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 2016 (Sub 1069)	1.781	2.289	654,342	$ 3,323,860		$ 3,323,860
2	May	2.090	2.289	641,603	1,279,806		1,279,806
3	June	2.453	2.289	721,182	(1,180,214)		(1,180,214)
4	July	2.960	2.289	751,098	(5,037,465)		(5,037,465)
5	August	2.791	2.289	808,252	(4,057,587)		(4,057,587)
6	September	2.440	2.289	785,140	(1,187,366)		(1,187,366)
7	October	2.125	2.289	725,884	1,193,499		1,193,499
8	November	2.013	2.289	662,814	1,830,758		1,830,758
9	December (1) (New Rates - Sub 1107)	2.851	2.274	624,718	(3,899,417)		(3,899,417)
10	January 2017	2.945	2.256	672,899	(4,634,992)		(4,634,992)
11	February	2.322	2.253	655,990	(450,665)		(450,665)
12	March	3.046	2.253	644,249	(5,111,216)		(5,111,216)
13	Total Test Period			8,348,171	$ (17,931,000)	$ -	$ (17,931,000)
14	Less: Proposed (under) collection deferral						17,931,000
15	Booked Over Recovery April 2016 to March 2017						$ -
16	Normalized Test Period MWH Sales	Exhibit 4					8,347,370
17	Experience Modification Increment (Decrement) cents/KWh						-
18	Annual Interest Rate						10%
19	Monthly Interest Rate						0.83333%
20	Number of Months (October 2016 - May 2018)						20
21	Interest						$ -
22	EMF Interest Decrement						-

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

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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, 2017
Docket E-2, Sub 1146

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 2016 (Sub 1069)		1.830	2.126	32,384	$ 95,833		$ 95,833
2	May		2.141	2.126	32,030	(4,901)		(4,901)
3	June		2.859	2.126	31,956	(234,110)		(234,110)
4	July		3.605	2.126	31,561	(466,629)		(466,629)
5	August		3.567	2.126	32,537	(468,976)		(468,976)
6	September		3.134	2.126	31,226	(314,820)		(314,820)
7	October		2.538	2.126	31,349	(129,160)		(129,160)
8	November		2.236	2.126	30,959	(33,975)		(33,975)
9	December (1) (New Rates - Sub 1107)		1.995	1.508	30,385	(163,444)		(163,444)
10	January 2017		0.922	0.720	30,959	(62,657)		(62,657)
11	February		0.570	0.596	30,582	8,064		8,064
12	March		0.727	0.596	30,913	(40,412)		(40,412)
13	Total Test Period				376,840	$ (1,815,185)	$ -	$ (1,815,185)
14	Less: Proposed (under) collection deferral							1,815,185
15	Booked Over Recovery April 2016 to March 2017							$ -
16	Normalized Test Period MWH Sales	Exhibit 4						377,137
17	Experience Modification Increment (Decrement) cents/KWh							-
18	Annual Interest Rate							10%
19	Monthly Interest Rate							0.83333%
20	Number of Months (October 2016 - May 2018)							20
21	Interest							$ -
22	EMF Interest Decrement							-

Notes:
(1) Adjustment included 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, 2017
Billing Period December 1, 2017 - November 30, 2018
Docket E-2, Sub 1146

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	60,973,121	36,921,171	15,187,842	1,880,312	11,128,006	8,348,171	376,840
2	Customer Growth MWH Adjustment	Workpaper 11	175,232	102,158	75,104	8,915	18,643	(800)	297
3	Weather MWH Adjustment	Workpaper 10	787,295	546,703	523,428	7,530	15,746	0	0
4	Total Adjusted MWH Sales	Sum Lines 1-3	61,935,648	37,570,033	15,786,375	1,896,757	11,162,395	8,347,370	377,137
5	Test Period Fuel and Fuel Related Revenue *		$ 1,437,575,909	$ 863,258,746					
6	Test Period Fuel and Fuel Related Expense *		$ 1,488,274,653	$ 896,656,489					
7	Test Period Unadjusted Over/(Under) Recovery	Line 5 - Line 6	$ (50,698,744)	$ (33,397,743)					

Line No.	Description	Winter Coincidental Peak (CP) KW
8	Total System Peak	12,911,246
9	NC Retail	7,831,936
10	NC Residential Peak	4,408,550
11	NC Small General Service	407,079
12	NC Medium General Service	1,999,996
13	NC Large General Service	1,016,310

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.

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, 2017

Billing Period December 1, 2017 - November 30, 2018

Docket E-2, Sub 1146

Unit	Rate Case Docket E-2, Sub 1069	Fuel Docket E-2, Sub 1107	Proposed Capacity Rating MW
Brunswick 1	938	938	938
Brunswick 2	932	932	932
Harris 1	928	928	928
Robinson 2	741	741	741
Total Company	3,539	3,539	3,539

Duke Energy Progress, LLC. **Ward Exhibit 6**
North Carolina Annual Fuel and Fuel Related Expense
Monthly Fuel and Baseload Report for March 2016
Test Period Twelve Months Ended March 31, 2017
Docket E-2, Sub 1146

Monthly Fuel Filing and Baseload Report Cover Sheet

Exhibit 6
Schedule 1

Duke Energy Progress
Summary of Monthly Fuel Report

Docket No. E-2, Sub 1132

Line No.	Fuel Expenses:		March 2017		12 Months Ended March 2017
1	Total Fuel and Fuel-Related Costs	$	130,086,898	$	1,488,274,653
	MWH sales:				
2	Total System Sales		4,924,762		67,312,343
3	Less intersystem sales		281,366		6,339,221
4	Total sales less intersystem sales		4,643,396		60,973,122
5	Total fuel and fuel-related costs (¢/KWH) (Line 1/Line 4)		2.802		2.441
6	Current fuel & fuel-related cost component (¢/KWH) (per Schedule 4, Line 5a Total)		2.171		
	Generation Mix (MWH):				
	Fossil (By Primary Fuel Type):				
7	Coal		654,479		11,114,200
8	Oil		7,534		95,472
9	Natural Gas - Combustion Turbine		205,440		3,282,999
10	Natural Gas - Combined Cycle		1,798,274		18,695,952
11	Total Fossil		2,665,728		33,188,624
12	Nuclear		1,700,086		29,033,303
13	Hydro - Conventional		33,875		339,751
14	Solar Distributed Generation		24,799		188,088
15	Total MWH generation		4,424,488		62,749,766

Notes: Detail amounts may not add to totals shown due to rounding.
Line 1, 12 months ended, includes an adjustment of $2,163,096 to true up April through November 2016.

Exhibit 6
Schedule 2

Duke Energy Progress
Details of Fuel and Fuel-Related Costs

Docket No. E-2, Sub 1132

Description	March 2017	12 Months Ended March 2017
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0456949 coal blending merger savings	$ -	$ (1,498,733)
0501016 coal procurement merger savings	-	1,149,172
0501016 transportation merger savings	-	2,872,204
0501110 coal consumed - steam	22,256,568	373,206,040
0501310 fuel oil consumed - steam	991,797	7,519,062
Total Steam Generation - Account 501	23,248,365	383,247,745
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	11,488,530	195,998,821
0518500 nuclear fuel savings	-	(3,817)
0518600 - Disposal Cost	-	-
Total Nuclear Generation - Account 518	11,488,530	195,995,003
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	8,150,342	132,482,468
0547000 natural gas consumed - Combined Cycle	51,766,200	546,454,554
0547123 gas capacity merger savings	-	(407,657)
0547200 fuel oil consumed	263,837	9,713,917
Total Other Generation - Account 547	60,180,379	688,243,282
Reagents		
Catalyst Depreciation	595,847	7,186,027
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	1,123,618	18,320,191
0502160 reagent procurement merger savings	-	(328,214)
Total Reagents	1,719,465	25,178,004
By-products		
Net proceeds from sale of by-products	5,706,358	16,578,637
0502161 by-product merger savings	-	63,758
Total By-products	5,706,358	16,642,395
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	102,343,096	1,309,306,429
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (renewables)	3,091,243	36,036,316
Fuel and fuel-related component of purchased power	32,170,019	295,282,502
Total Purchased Power and Net Interchange - Account 555	35,261,262	331,318,818
Less fuel and fuel-related costs recovered through intersystem sales - Account 447	7,517,460	152,350,594
Total Fuel and Fuel-Related Costs	$ 130,086,898	$ 1,488,274,653

Notes: Detail amounts may not add to totals shown due to rounding.
12 months ended 0518100 burnup of owned fuel includes an adjustment of $2,163,096 to true up April through November 2016

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

MARCH 2017

Purchased Power	**Total**	**Capacity**	**Non-capacity**			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Broad River Energy, LLC.	$ 3,702,114	$ 1,050,012	56,855	$ 2,403,063	$ 249,039	-
City of Fayetteville	720,627	714,375	-	6,252	-	-
DE Carolinas - Native Load Transfer	9,973,251	-	352,735	8,641,869	1,332,969	$ (1,587)
DE Carolinas - Native Load Transfer Benefit	664,725	-	-	664,725	-	-
DE Carolinas - Fees	(88,789)	-	-	-	(88,789)	
Haywood EMC	29,850	29,850	-	-	-	
NCEMC	3,466,508	2,654,445	19,076	812,063	-	
PJM Interconnection, LLC.	(267,539)	-	1,462	21,915	(289,454)	-
Southern Company Services	4,183,906	772,044	108,992	3,011,749	400,113	
	$ 22,384,653	**$ 5,220,726**	**539,120**	**$ 15,561,636**	**$ 1,603,878**	**$ (1,587)**
Renewable Energy	**$ 18,346,502**	**$ -**	**277,842**	**$ -**	**$ 18,070,645**	**$ 275,857**
Non-dispatchable						
DE Carolinas - Emergency	$ 13,590	-	183	$ 8,290		$ 5,300
Smurfit Stone Container Corp	16,967	-	503	15,921		1,046
Generation Imbalance	1,462		43	892		570
Qualifying Facilities	7,735,490	$ 1,116,813	127,990	-		6,618,677
	$ 7,767,509	**$ 1,116,813**	**128,719**	**$ 25,103**	**$ -**	**$ 6,625,593**
Total Purchased Power	**$ 48,498,664**	**$ 6,337,539**	**945,681**	**$ 15,586,739**	**$ 19,674,523**	**$ 6,899,863**

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

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

MARCH 2017

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Market Based:					
NCEMC Purchase Power Agreement	$ 1,220,272	$ 652,500	15,274	$ 577,278	$ (9,506)
PJM Interconnection, LLC.	27,253	-	584	18,356	8,897
Other:					
DE Carolinas - Native Load Transfer Benefit	$ 134,868	-	-	$ 134,868	-
DE Carolinas - Native Load Transfer	7,064,004	-	265,506	6,786,958	$ 277,046
Generation Imbalance	60	-	2	-	60
Total Intersystem Sales	**$ 8,446,457**	**$ 652,500**	**281,366**	**$ 7,517,460**	**$ 276,497**

* 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 2017

Purchased Power	**Total**	**Capacity**	**Non-capacity**			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Broad River Energy, LLC.	$ 85,597,727	$ 43,691,103	888,779	$ 35,027,454	$ 6,939,437	$ (60,267)
City of Fayetteville	13,977,169	12,756,100	12,698	1,085,829	135,387	(147)
DE Carolinas - Native Load Transfer	43,087,403	-	1,496,908	32,020,823	10,436,964	629,616
DE Carolinas - Native Load Transfer Benefit	1,867,055	-	-	1,867,052	-	3
DE Carolinas - Fees	217,071	-	-	-	217,071	
Haywood EMC	353,848	353,848	-	-	-	
NCEMC	48,501,357	35,944,858	298,596	12,556,499	-	
PJM Interconnection, LLC.	367,824	-	23,972	391,300	(23,649)	173
Southern Company Services	49,377,629	13,039,940	1,175,995	31,673,122	4,664,567	
	$ 243,347,083	**$ 105,785,849**	**3,896,948**	**$ 114,622,079**	**$ 22,369,777**	**$ 569,378**
Renewable Energy	**$ 203,720,329**	**$ -**	**2,906,463**	**$ -**	**$ 193,982,878**	**$ 9,737,451**
Non-dispatchable						
DE Carolinas - Emergency	$ 61,201	-	1,240	$ 37,333		$ 23,868
Smurfit Stone Container Corp	232,755	-	7,894	214,449		18,306
Generation Imbalance	134,109	-	5,199	92,302		41,807
Qualifying Facilities	47,158,289	$ 9,774,492	668,369	-		37,383,797
	$ 47,586,353	**$ 9,774,492**	**682,702**	**$ 344,083**	**$ -**	**$ 37,467,778**
Total Purchased Power	**$ 494,653,765**	**$ 115,560,341**	**7,486,113**	**$ 114,966,162**	**$ 216,352,655**	**$ 47,774,607**

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

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

Twelve Months Ended MARCH 2017

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
SC Electric & Gas - Emergency	$ 43,616	-	741	$ 34,490	$ 9,126
SC Public Service Authority - Emergency	11,284	-	265	7,920	3,364
Market Based:					
NCEMC	$ 8,910	-	270	$ 7,015	$ 1,895
NCEMC Purchase Power Agreement	11,734,563	$ 7,830,000	114,332	3,468,516	436,047
PJM Interconnection, LLC.	3,872,394	-	88,425	2,635,364	1,237,030
Other:					
DE Carolinas - Native Load Transfer Benefit	$ 8,687,075	-	-	$ 8,581,761	105,314
DE Carolinas - Native Load Transfer	145,849,004	-	6,132,275	137,542,219	8,306,785
Generation Imbalance	89,581	-	2,913	73,309	16,272
Total Intersystem Sales	**$ 170,296,427**	**$ 7,830,000**	**6,339,221**	**$ 152,350,594**	**$ 10,115,833**

* Sales for resale other than native load priority.

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

Exhibit 6
Schedule 4

Duke Energy Progress
Over / (Under) Recovery of Fuel Costs
March 2017

Line No.			Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total
1	1a. System Retail kWh sales	Input						4,643,396,027
	1b. System kWh Sales at generation	Input						4,811,562,554
2	2a. DERP Net Metered kWh generation	Input						160,035
	2b. Line loss percentage from Cost of Service	Input Annually						4.134%
	2c. DERP Net Metered kWh at generation	L2a * (1 + 2b)						166,651
3	Adjusted System kWh sales	L1b + L2c						4,811,729,205
4	4a. N.C. Retail kWh sales	Input	1,189,430,805	137,527,862	841,518,117	644,249,243	30,912,691	2,843,638,718
	4b. Line loss percentage from Cost of Service	Input Annually	4.702%	4.701%	4.514%	3.483%	4.700%	
	4c. NC kWh Sales at generation	4a * (1+4b)	1,245,357,841	143,993,047	879,504,245	666,688,444	32,365,587	2,967,909,164
	4d. NC allocation % by customer class	Calculated	41.961%	4.852%	29.634%	22.463%	1.091%	
	4e. NC retail % of actual system total	L4c NC Total / L1b Total System						61.683%
	4f. NC retail % of adjusted system total	L4c NC Total / L3 Total System						61.681%
5	Approved fuel and fuel-related rates (¢/kWh)							
	5a Billed rates by class (¢/kWh)	L5g	1.993	2.088	2.431	2.253	0.596	2.171
	5b Billed fuel expense	L4a * L5a / 100	$23,705,356	$2,871,582	$20,457,305	$14,514,935	$184,240	$61,733,418
6	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)							
	Allocation changes:							
	6a Docket E-2, Sub 1107 allocation factor	Input Annually	38.22%	4.59%	31.07%	25.82%	0.30%	100.00%
	6b System incurred expense	Input						$127,000,920
	6c NC incurred expense by class	L4f * L6a * L6b	$29,939,804	$3,595,597	$24,338,820	$20,226,210	$235,006	$78,335,437
	6d NC Incurred base fuel rates (¢/kWh)	L6c / L4a * 100	2.51715	2.61445	2.89225	3.13950	0.76023	2.75476
7	Incurred renewable purchased power capacity rates (¢/kWh)							
	7a NC retail production plant %	Input Annually						63.15%
	7b Production plant allocation factors	Input Annually	46.860%	6.493%	30.750%	15.886%	0.011%	100.00%
	7c System incurred expense	Input						$3,091,243
	7d NC incurred renewable capacity expense	L7a* L7b* L7c	$914,830	$126,752	$600,316	$310,125	$221	$1,952,244
	7e NC incurred expense by class	L7d / L4a * 100	0.07691	0.09216	0.07134	0.04814	0.00072	0.06865
8	Total incurred rates by class (¢/kWh)	L6h + 7e	2.5941	2.7066	2.9636	3.1876	0.7610	
9	Difference in ¢/kWh (billed - incurred)	L5a - L8	(0.60106)	(0.61861)	(0.53259)	(0.93464)	(0.16495)	
10	Over / (under) recovery	L9 * L4a / 100	($7,149,193)	($850,761)	($4,481,841)	($6,021,411)	($50,990)	($18,554,196)
11	Prior period adjustments - Note 1	Input						
12	Total over / (under) recovery	L10 + L11	($7,149,193)	($850,761)	($4,481,841)	($6,021,411)	($50,990)	($18,554,196)
13	Total System Incurred Expenses							$130,092,163
14	Less: Jurisdictional allocation adjustment	Input						$5,264
15	Total Fuel and Fuel-related Costs per Schedule 2							$130,086,898
17	Over / (under) recovery for each month of the current test period							

		Over / (Under) Recovery						
		Total To Date	Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total Company
	April 2016	$ 10,069,491	$ 989,962	$ 387,235	$ 5,272,601	$ 3,323,860	$ 95,833	$ 10,069,491
	May	$ 12,992,358	$ (2,639,367)	$ 133,103	$ 4,154,226	$ 1,279,806	$ (4,901)	$ 2,922,867
	June	$ 9,797,247	$ (3,066,524)	$ (111,794)	$ 1,397,531	$ (1,180,214)	$ (234,110)	$ (3,195,111)
	July	$ (4,406,945)	$ (5,283,467)	$ (575,553)	$ (2,841,078)	$ (5,037,465)	$ (466,629)	$ (14,204,192)
	August	$ (10,771,621)	$ (1,010,695)	$ (179,944)	$ (647,474)	$ (4,057,587)	$ (468,976)	$ (6,364,676)
	September	$ (9,819,795)	$ (171,336)	$ 301,985	$ 2,323,363	$ (1,187,366)	$ (314,820)	$ 951,826
	October	$ (9,996,605)	$ (4,602,060)	$ 21,331	$ 3,339,580	$ 1,193,499	$ (129,160)	$ (176,810)
	November	$ (7,502,826)	$ (2,392,665)	$ 58,095	$ 3,031,566	$ 1,830,758	$ (33,975)	$ 2,493,779
_/1	December	$ (17,716,442)	$ (2,616,780)	$ (639,263)	$ (2,894,712)	$ (3,899,417)	$ (163,444)	$ (10,213,616)
	January 2017	$ (24,305,228)	$ 1,977,996	$ (180,208)	$ (2,743,559)	$ (5,566,823)	$ (76,192)	$ (6,588,786)
	February	$ (25,570,602)	$ 183,711	$ 71,681	$ (149,505)	$ (1,368,658)	$ (2,603)	$ (1,265,374)
	March	$ (44,124,798)	$ (7,149,193)	$ (850,761)	$ (4,481,841)	$ (6,021,411)	$ (50,990)	$ (18,554,196)
	Total		$ (25,780,418)	$ (1,564,093)	$ 5,760,698	$ (20,691,018)	$ (1,849,967)	$ (44,124,798)

Notes:
Detail amounts may not recalculate due to percentages presented as rounded.
_/1 Includes prior period adjustments.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2017

Description	Weatherspoon CT	Lee CC	Sutton CC/CT	Robinson Nuclear	Asheville Steam	Asheville CT	Roxboro Steam	Mayo Steam
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	$3,807,209	-	$8,681,740	$4,068,807
Oil	-	-	-	81,619	1,414	-	618,111	293,178
Gas - CC	-	18,910,532	13,825,841	-	-	-	-	-
Gas - CT	24	-	-	-	-	108,618	-	-
Total	$24	$18,910,532	$13,825,841	$81,619	$3,808,623	$108,618	$9,299,851	$4,361,985
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	314.69	-	320.83	320.15
Oil	-	-	-	1,964.83	-	-	1,453.76	1,413.72
Gas - CC	-	408.89	470.51	-	-	-	-	-
Gas - CT	-	-	-	-	-	859.05	-	-
Weighted Average	-	408.89	470.51	1,964.83	314.80	859.05	338.36	337.71
Cost of Fuel Burned ($)								
Coal	-	-	-	-	$4,041,447	-	$11,848,099	$6,367,022
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	11,487	-	-	-	62,854	243,236	579,181	349,762
Gas - CC	-	18,910,532	13,825,841	-	-	-	-	-
Gas - CT	24	-	-	-	-	108,618	-	-
Nuclear	-	-	-	-	-	-	-	-
Total	$11,511	$18,910,532	$13,825,841	-	$4,104,301	$351,854	$12,427,280	$6,716,784
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	288.30	-	316.65	316.35
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	1,507.48	-	-	-	1,366.09	1,366.11	1,376.38	1,356.03
Gas - CC	-	408.89	470.51	-	-	-	-	-
Gas - CT	-	-	-	-	-	859.05	-	-
Nuclear	-	-	-	-	-	-	-	-
Weighted Average	1,510.57	408.89	470.51	-	291.82	1,155.55	328.43	329.50
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	3.23	-	3.46	3.42
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	-	-	-	-	15.35	19.65	15.17	14.64
Gas - CC	-	2.88	3.30	-	-	-	-	-
Gas - CT	-	-	-	-	-	12.30	-	-
Nuclear	-	-	-	-	-	-	-	-
Weighted Average	-	2.88	3.30	-	3.27	16.59	3.58	3.56
Burned MBTU's								
Coal	-	-	-	-	1,401,828	-	3,741,746	2,012,664
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	762	-	-	-	4,601	17,805	42,080	25,793
Gas - CC	-	4,624,893	2,938,496	-	-	-	-	-
Gas - CT	-	-	-	-	-	12,644	-	-
Nuclear	-	-	-	-	-	-	-	-
Total	762	4,624,893	2,938,496	-	1,406,429	30,449	3,783,826	2,038,457
Net Generation (mWh)								
Coal	-	-	-	-	125,175	-	342,916	186,388
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	(26)	-	(41)	-	409	1,238	3,819	2,389
Gas - CC	-	656,569	419,374	-	-	-	-	-
Gas - CT	(17)	-	-	-	-	883	-	-
Nuclear	-	-	-	(4,247)	-	-	-	-
Hydro (Total System)								
Solar (Total System)								
Total	(43)	656,569	419,333	(4,247)	125,584	2,121	346,735	188,777
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	-	-	$111,982	$49,346
Limestone	-	-	-	-	141,689	-	283,577	239,697
Re-emission Chemical	-	-	-	-	-	-	(1,658)	-
Sorbents	-	-	-	-	-	-	85,785	85,168
Urea	-	-	-	-	98,817	-	-	-
Total	-	-	-	-	240,506	-	479,685	374,211

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.

Fuel cost information on this report does not reflect intercompany sharing of fuel-related merger savings between Duke Energy Carolinas and Duke Energy Progress.

Lee and Wayne oil burn is associated with inventory consumption shown on Schedule 6 for Wayne.

Re-emission chemical reagent expense is not recoverable in NC.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2017

Description	Brunswick Nuclear	Blewett CT	Wayne County CT	Darlington CT	Smith Energy Complex CC/CT	Harris Nuclear	Current Month	Total 12 ME March 2017
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	-	-	$16,557,756	$356,398,021
Oil	19,562	-	296	-	-	(3,311)	1,010,869	18,32[illegible]26
Gas - CC	-	-	-	-	19,029,827	-	51,766,200	546,454,554
Gas - CT	-	-	398,597	39,782	7,603,321	-	8,150,342	132,482,468
Total	19,562	-	$398,893	$39,782	$26,633,148	(3,311)	$77,485,167	$1,053,656,970
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	-	-	319.23	316.43
Oil	1,807.95	-	-	-	-	-	1,475.89	1,169.71
Gas - CC	-	-	-	-	369.45	-	407.15	411.55
Gas - CT	-	-	395.82	413.96	371.31	-	375.48	358.28
Weighted Average	1,807.95	-	396.11	413.96	369.98	-	384.73	371.06
Cost of Fuel Burned ($)								
Coal	-	-	-	-	-	-	$22,256,568	$373,206,039
Oil - CC	-	-	-	-	198	-	198	335,390
Oil - Steam/CT	-	8,916	-	-	-	-	1,255,436	16,897,587
Gas - CC	-	-	-	-	19,029,827	-	51,766,200	546,454,554
Gas - CT	-	-	398,597	39,782	7,603,321	-	8,150,342	132,482,468
Nuclear	6,624,782	-	-	-	-	4,863,748	11,488,530	195,998,221
Total	$6,624,782	$8,916	$398,597	$39,782	$26,633,346	$4,863,748	$94,917,274	$1,265,374,860
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	-	-	311.01	318.45
Oil - CC	-	-	-	-	1,650.00	-	1,650.00	1,838.54
Oil - Steam/CT	-	1,667.52	-	-	-	-	1,370.93	1,326.95
Gas - CC	-	-	-	-	369.45	-	407.15	411.55
Gas - CT	-	-	395.82	413.96	371.31	-	375.48	358.28
Nuclear	63.87	-	-	-	-	65.45	64.53	64.09
Weighted Average	63.87	1,667.52	395.82	413.96	369.98	65.45	237.67	213.00
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	-	-	3.40	3.36
Oil - CC	-	-	-	-	19.80	-	19.80	40.73
Oil - Steam/CT	-	-	-	-	-	-	16.66	17.85
Gas - CC	-	-	-	-	2.63	-	2.88	2.92
Gas - CT	-	-	5.35	11.77	3.86	-	3.97	4.04
Nuclear	0.67	-	-	-	-	0.68	0.68	0.68
Weighted Average	0.67	-	5.35	38.25	2.90	0.68	2.15	2.02
Burned MBTU's								
Coal	-	-	-	-	-	-	7,156,238	117,193,940
Oil - CC	-	-	-	-	12	-	12	18,242
Oil - Steam/CT	-	535	-	-	-	-	91,576	1,273,417
Gas - CC	-	-	-	-	5,150,865	-	12,714,254	132,779,863
Gas - CT	-	-	100,702	9,610	2,047,679	-	2,170,635	36,977,753
Nuclear	10,373,004	-	-	-	-	7,431,203	17,804,207	305,824,044
Total	10,373,004	535	100,702	9,610	7,198,556	7,431,203	39,936,922	594,067,259
Net Generation (mWh)								
Coal	-	-	-	-	-	-	654,479	11,114,200
Oil - CC	-	-	-	-	1	-	1	823
Oil - Steam/CT	-	(20)	-	(234)	-	-	7,533	94,649
Gas - CC	-	-	-	-	722,331	-	1,798,274	18,695,952
Gas - CT	-	-	7,447	338	196,789	-	205,440	3,282,999
Nuclear	986,692	-	-	-	-	717,641	1,700,086	29,033,303
Hydro (Total System)							33,875	339,751
Solar (Total System)							24,799	188,088
Total	986,692	(20)	7,447	104	919,121	717,641	4,424,488	62,749,766
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	$27,558	-	$188,886	$3,096,440
Limestone	-	-	-	-	-	-	664,963	10,634,944
Re-emission Chemical	-	-	-	-	-	-	(1,658)	115,510
Sorbents	-	-	-	-	-	-	170,953	3,561,655
Urea	-	-	-	-	-	-	98,817	1,027,152
Total	-	-	-	-	27,558	-	1,121,960	18,435,700

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2017

Description	Weatherspoon	Lee	Sutton	Robinson	Asheville
Coal Data:					
Beginning balance	-	-	-	-	144,698
Tons received during period	-	-	-	-	48,486
Inventory adjustments	-	-	-	-	-
Tons burned during period	-	-	-	-	56,145
Ending balance	-	-	-	-	137,039
MBTUs per ton burned	-	-	-	-	24.97
Cost of ending inventory ($/ton)	-	-	-	-	71.98
Oil Data:					
Beginning balance	661,306	-	3,164,645	78,040	2,998,341
Gallons received during period	-	-	-	30,102	-
Miscellaneous use and adjustments	(7)	-	-	-	(3,826)
Gallons burned during period	5,444	-	-	30,102	162,970
Ending balance	655,855	-	3,164,645	78,040	2,831,545
Cost of ending inventory ($/gal)	2.11	-	2.80	2.74	1.88
Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	4,449,913	2,855,342	-	12,239
MCF burned during period	-	4,449,913	2,855,342	-	12,239
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	-	-	-	-	12,218
Tons received during period	-	-	-	-	1,125
Inventory adjustments	-	-	-	-	-
Tons consumed during period	-	-	-	-	3,158
Ending balance	-	-	-	-	10,185
Cost of ending inventory ($/ton)	-	-	-	-	42.77

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

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2017

Description	Roxboro	Mayo	Brunswick	Blewett	Wayne County
Coal Data:					
Beginning balance	1,323,885	539,325	-	-	-
Tons received during period	106,377	50,441	-	-	-
Inventory adjustments	-	-	-	-	-
Tons burned during period	145,361	78,928	-	-	-
Ending balance	1,284,901	510,838	-	-	-
MBTUs per ton burned	25.74	25.50	-	-	-
Cost of ending inventory ($/ton)	81.48	80.67	-	-	-
Oil Data:					
Beginning balance	481,996	287,722	171,953	800,912	11,982,942
Gallons received during period	308,104	150,276	7,837	-	-
Miscellaneous use and adjustments	(7,517)	(4,229)	-	-	-
Gallons burned during period	305,084	187,298	-	3,806	-
Ending balance	477,499	246,471	179,790	797,106	11,982,942
Cost of ending inventory ($/gal)	1.90	1.87	2.74	2.34	2.41
Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	-	-	-	96,211
MCF burned during period	-	-	-	-	96,211
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	107,921	19,835	-	-	-
Tons received during period	(3,856)	4,097	-	-	-
Inventory adjustments	-	-	-	-	-
Tons consumed during period	7,581	6,103	-	-	-
Ending balance	96,484	17,829	-	-	-
Cost of ending inventory ($/ton)	35.46	36.45	-	-	-

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2017

Description	Darlington	Smith Energy Complex	Harris	Current Month	Total 12 ME March 2017
Coal Data:					
Beginning balance	-	-	-	2,007,908	2,107,514
Tons received during period	-	-	-	205,304	4,440,772
Inventory adjustments	-	-	-	-	36,131
Tons burned during period	-	-	-	280,434	4,651,639
Ending balance	-	-	-	1,932,778	1,932,778
MBTUs per ton burned	-	-	-	25.52	25.19
Cost of ending inventory ($/ton)	-	-	-	80.60	80.60
Oil Data:					
Beginning balance	10,034,417	8,141,688	297,499	39,101,461	37,143,136
Gallons received during period	-	-	-	496,319	11,350,512
Miscellaneous use and adjustments	-	-	-	(15,579)	(277,187)
Gallons burned during period	-	85	-	694,789	9,329,049
Ending balance	10,034,417	8,141,603	297,499	38,887,412	38,887,412
Cost of ending inventory ($/gal)	2.36	2.32	2.74	2.36	2.36
Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	9,277	6,992,365	-	14,415,347	164,405,110
MCF burned during period	9,277	6,992,365	-	14,415,347	164,405,110
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	-	-	-	139,974	155,043
Tons received during period	-	-	-	1,366	275,336
Inventory adjustments	-	-	-	-	(10,345)
Tons consumed during period	-	-	-	16,842	295,536
Ending balance	-	-	-	124,498	124,498
Cost of ending inventory ($/ton)	-	-	-	36.20	36.20

Exhibit 6
Schedule 7

DUKE ENERGY PROGRESS

ANALYSIS OF COAL PURCHASED

MARCH 2017

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ASHEVILLE	SPOT	1,739	$ 151,084	86.90
	CONTRACT	46,747	3,550,505	75.95
	ADJUSTMENTS	-	105,620	-
	TOTAL	48,486	3,807,209	78.52
MAYO	SPOT	-	-	-
	CONTRACT	50,441	3,943,757	78.19
	ADJUSTMENTS	-	125,050	-
	TOTAL	50,441	4,068,807	80.67
ROXBORO	SPOT	11,657	831,567	71.33
	CONTRACT	94,720	7,224,703	76.27
	ADJUSTMENTS	-	625,470	-
	TOTAL	106,377	8,681,739	81.61
ALL PLANTS	SPOT	13,396	982,651	73.35
	CONTRACT	191,908	14,718,964	76.70
	ADJUSTMENTS	-	856,140	-
	TOTAL	205,304	$ 16,557,756	$ 80.65

Exhibit 6
Schedule 8

DUKE ENERGY PROGRESS
ANALYSIS OF COAL QUALITY RECEIVED
MARCH 2017

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
ASHEVILLE	6.27	10.46	12,476	1.63
MAYO	7.33	7.95	12,598	1.56
ROXBORO	6.77	8.46	12,719	2.13

Exhibit 6
Schedule 9

DUKE ENERGY PROGRESS

ANALYSIS OF OIL PURCHASED

MARCH 2017

	BRUNSWICK	MAYO	ROBINSON	ROXBORO
VENDOR	Selma Tank Farm	Greensboro Tank Farm and Selma Tank Farm	Selma Tank Farm	Greensboro Tank Farm and Selma Tank Farm
SPOT/CONTRACT	Contract	Contract	Contract	Contract
SULFUR CONTENT %	0	0	0	0
GALLONS RECEIVED	7,837	150,276	30,102	308,104
TOTAL DELIVERED COST	$ 19,562	$ 293,178	$ 81,619	$ 618,111
DELIVERED COST/GALLON	$ 2.50	$ 1.95	$ 2.71	$ 2.01
BTU/GALLON	138,000	138,000	138,000	138,000

Note:
Price adjustments of $1,414, $(3,311) and $296 for the Asheville, Harris and Wayne County stations, respectively, are excluded.

Duke Energy Progress

Power Plant Performance Data

Twelve Month Summary

April, 2016 - March, 2017

Nuclear Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Brunswick 1	8,216,856	938	100.00	98.52
Brunswick 2	7,576,974	932	92.81	95.51
Harris 1	7,493,245	928	92.18	90.24
Robinson 2	5,746,228	741	88.52	86.95

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2016 through March, 2017
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Lee Energy Complex	1A	1,269,760	196	73.94	84.23
Lee Energy Complex	1B	1,320,063	195	77.27	90.15
Lee Energy Complex	1C	1,272,152	197	73.64	87.04
Lee Energy Complex	ST1	2,414,881	378	72.85	81.69
Lee Energy Complex	Block Total	6,276,856	967	74.12	84.80
Richmond County CC	7	942,591	172	62.56	70.99
Richmond County CC	8	925,695	170	62.07	70.45
Richmond County CC	ST4	1,076,737	169	72.67	70.94
Richmond County CC	9	1,430,808	193	84.68	91.67
Richmond County CC	10	1,442,308	193	85.36	91.60
Richmond County CC	ST5	1,921,058	249	88.13	92.26
Richmond County CC	Block Total	7,739,197	1,146	77.09	82.73
Sutton Energy Complex	1A	1,439,909	198	83.00	94.70
Sutton Energy Complex	1B	1,458,491	198	84.08	95.92
Sutton Energy Complex	ST1	1,789,393	265	77.01	95.66
Sutton Energy Complex	Block Total	4,687,793	662	80.92	95.23

Notes:

- Effective January 2017, a change in capacity rating methodology could impact performance trending against historical results reported prior to January 2017.
- 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, 2016 through March, 2017

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Mayo 1	2,060,395	735	32.01	88.58
Roxboro 2	2,553,927	672	43.40	95.29
Roxboro 3	2,346,656	694	38.61	92.22
Roxboro 4	1,928,804	703	31.30	92.37

Notes:
- Effective January 2017, a change in capacity rating methodology could impact performance trending against historical results reported prior to January 2017.
- 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, 2016 through March, 2017
Other Cycling Steam Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Asheville	1	709,380	190	42.57	81.80
Asheville	2	591,729	190	35.51	80.14
Roxboro	1	980,791	379	29.51	96.46

Notes:

- Effective January 2017, a change in capacity rating methodology could impact performance trending against historical results reported prior to January 2017.
- 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, 2016 through March, 2017
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Asheville CT	203,916	343	89.40
Blewett CT	-10	59	98.97
Darlington CT	113,022	808	89.66
Richmond County CT	2,417,144	837	88.91
Sutton CT	-477	67	91.58
Wayne County CT	579,050	903	91.36
Weatherspoon CT	451	143	94.57

Notes:
- Effective January 2017, a change in capacity rating methodology could impact performance trending against historical results reported prior to January 2017.
- 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, 2016 through March, 2017
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Blewett	70,086	27.0	74.54
Marshall	5,535	4.0	33.93
Tillery	104,473	84.0	93.67
Walters	159,657	113.0	98.05

Notes:
- Effective January 2017, a change in capacity rating methodology could impact performance trending against historical results reported prior to January 2017.
- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Ward Workpaper 1
Docket No. E-2, Sub 1146

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period December 2017 - November 2018

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs	7,412,751	8,001,034	7,399,204	5,908,200	28,721,189
Cost	$ 51,154,344	$ 57,637,077	$ 52,900,847	$ 43,284,557	$ 204,976,825
$/MWhs	$ 6.9009	$ 7.2037	$ 7.1495	$ 7.3262	

Avg. $/MWhs	**$ 7.1368**
Cents per kWh	**0.7137**

	Unit		Dec'2017 - Nov'18
MDC			
	Brunswick 1	MW	938
	Brunswick 2	MW	932
	Harris 1	MW	928
	Robinson 1	MW	741
			3,539
Hours in Year			8,760
Generation in GWhs			
	Brunswick 1	GWh	7,413
	Brunswick 2	GWh	8,001
	Harris 1	GWh	7,399
	Robinson 1	GWh	5,908
			28,721
	Proposed Nuclear Capacity Factor		**92.6%**

Note: Totals may not sum due to rounding

Ward Workpaper 2
Docket No. E-2, Sub 1146

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period December 2017 - November 2018

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs with NERC applied	7,649,094	7,600,165	7,177,341	5,144,893	27,571,494
Hours	8,760	8,760	8,760	8,760	8,760
MDC	938	932	928	741	3,539
Capacity Factor-NERC 5yr Avg	0.9309	0.9309	0.8829	0.7926	
Cost ($)	$ 54,589,902	$ 54,240,713	$ 51,223,110	$ 36,717,975	$ 196,771,701
Avg. $/MWHs					**$ 7.1368**
Cents per kWh					**0.7137**

2016	Capacity Rating	NCF Rating	Weighted Average
Brunswick 1	938	0.9309	24.67
Brunswick 2	932	0.9309	24.52
Harris 1	928	0.8829	23.15
Robinson 1	741	0.7926	16.60
	3,539		**88.94**

Note: Totals may not sum due to rounding

Ward Workpaper 3
Docket No. E-2, Sub 1146

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation in MWhs
Billing Period December 2017 - November 2018

Resource Type		**Dec'17 - Nov'18**
Nuclear		29,282,736
Adjust for Lower Nuclear Capacity Factor		(561,547)
Adjusted Nuclear Total		28,721,189
Coal		9,223,373
Adjust for Lower Nuclear Capacity Factor		561,547
Adjusted Coal Total		9,784,920
Gas CT and CC Total		20,231,727
Total Hydro		598,023
Utility Owned Solar Generation		282,714
Total Net Generation		59,618,574
Purchases	1,097,307	
Purchases for REPS Compliance	2,553,652	
Other QF Purchases	2,272,698	
Allocated Economic Purchases	851,699	
Joint Dispatch purchases	1,628,921	8,404,277
Total Net Generation and Purchases		68,022,851
Sales Totals (intersystem sales, JDA sales)		(3,109,193)
Line Losses		(2,749,842)
Total NC System Sales		**62,163,816**

Note: Totals may not sum due to rounding

Ward Workpaper 4
Docket No. E-2, Sub 1146

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Fuel Costs ($)
Billing Period December 2017 - November 2018

Resource Type		**Dec'17 - Nov'18**
Nuclear		209,018,615
Adjust for Lower Nuclear Capacity Factor		(4,041,790)
Adjusted Nuclear		204,976,825
Coal		298,160,713
Adjust for Lower Nuclear Capacity Factor		18,152,935
Adjusted Coal Total		316,313,648
Reagent and By-Product Costs		23,900,904
Gas CT and CC Total		580,845,112
Total Hydro		-
Utility Owned Solar Generation		-
Total Generation Costs		1,126,036,488
Purchases	41,519,620	
Purchases for REPS Compliance	154,215,192	
Purchases for REPS Compliance Capacity	31,684,006	
Other QF Purchases	0	
Allocated Economic Purchases	19,368,483	
Fuel Transfer Purchases	42,648,036	
Joint Dispatch savings	(1,894,189)	
Total Purchase Costs		287,541,147
Sales Totals (intersystem sales)	(9,531,312)	
Fuel Transfer Sales	(69,558,360)	
Total Sales Costs		(79,089,672)
Total Fuel and Related Expenses		**1,334,487,963**

Note: Totals may not sum due to rounding

Ward Workpaper 5
Docket No. E-2, Sub 1146

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Fuel Impacts
Billing Period December 2017 - November 2018

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
12/1/2017	$ 1,109,225	$ 1,678,893	$ (493,239)	$ (406,162)	$ (2,830,885)	$ 2,830,885	$ (19,548)	$ 19,548	$ -	$ -	$ -	$ -	$ -	$ -
1/1/2018	$ 760,406	$ 1,104,897	$ (1,897,748)	$ (3,020,405)	$ 9,103,540	$ (9,103,540)	$ 1,531,768	$ (1,531,768)	$ -	$ -	$ -	$ -	$ -	$ -
2/1/2018	$ 496,751	$ 742,439	$ (1,299,623)	$ (1,591,586)	$ (2,003,366)	$ 2,003,366	$ 4,980	$ (4,980)	$ -	$ -	$ -	$ -	$ -	$ -
3/1/2018	$ 835,373	$ 1,279,397	$ (333,528)	$ (608,762)	$ 3,328,107	$ (3,328,107)	$ 708,999	$ (708,999)	$ -	$ -	$ -	$ -	$ -	$ -
4/1/2018	$ 1,176,205	$ 1,822,564	$ (36,016)	$ (31,481)	$ 6,622,371	$ (6,622,371)	$ 1,076,194	$ (1,076,194)	$ -	$ -	$ -	$ -	$ -	$ -
5/1/2018	$ 1,014,068	$ 1,574,048	$ (119,054)	$ (192,612)	$ (2,551,175)	$ 2,551,175	$ (141,595)	$ 141,595	$ -	$ -	$ -	$ -	$ -	$ -
6/1/2018	$ 1,026,960	$ 1,571,642	$ (230,569)	$ (272,981)	$ (11,281,955)	$ 11,281,955	$ (1,338,942)	$ 1,338,942	$ -	$ -	$ -	$ -	$ -	$ -
7/1/2018	$ 1,339,179	$ 1,949,040	$ (465,266)	$ (659,615)	$ (7,672,523)	$ 7,672,523	$ (1,284,515)	$ 1,284,515	$ -	$ -	$ -	$ -	$ -	$ -
8/1/2018	$ 1,965,963	$ 2,897,823	$ (311,680)	$ (381,012)	$ (8,821,679)	$ 8,821,679	$ (1,578,825)	$ 1,578,825	$ -	$ -	$ -	$ -	$ -	$ -
9/1/2018	$ 4,123,980	$ 6,097,448	$ (62,484)	$ (81,701)	$ 291,485	$ (291,485)	$ 163,989	$ (163,989)	$ -	$ -	$ -	$ -	$ -	$ -
10/1/2018	$ 3,289,931	$ 5,059,523	$ (12,033)	$ (13,146)	$ (2,871,211)	$ 2,871,211	$ (242,562)	$ 242,562	$ -	$ -	$ -	$ -	$ -	$ -
11/1/2018	$ 2,230,442	$ 3,353,752	$ (181,830)	$ (154,148)	$ (8,223,035)	$ 8,223,035	$ (774,133)	$ 774,133	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 19,368,483		$ (5,443,071)		$ (26,910,324)		$ (1,894,189)		$ -		$ -		$ -	

Note: Totals may not sum due to rounding

	Fuel Transfer Payments	
	Purchases	Sales
12/1/2017	$ 3,931,151	$ 6,762,036
1/1/2018	$ 10,733,785	$ 1,630,245
2/1/2018	$ 3,091,397	$ 5,094,763
3/1/2018	$ 5,848,124	$ 2,520,017
4/1/2018	$ 8,226,302	$ 1,603,931
5/1/2018	$ 2,000,149	$ 4,551,323
6/1/2018	$ 210,016	$ 11,491,970
7/1/2018	$ 893,064	$ 8,565,587
8/1/2018	$ 564,101	$ 9,385,780
9/1/2018	$ 3,399,372	$ 3,107,887
10/1/2018	$ 3,076,143	$ 5,947,354
11/1/2018	$ 674,433	$ 8,897,468
	$ 42,648,036	$ 69,558,360
		$ 26,910,324

Ward Workpaper 6
Docket No. E-2, Sub 1146

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Payments
Billing Period December 2017 - November 2018

	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**
12/1/2017	247,152	137,469	(10,441)	10,441	247,152	147,910	$ 27.36	$ 26.58	$ 3,931,151	$ 6,762,036	$ -	$ 2,830,885
1/1/2018	55,722	382,331	(6,677)	6,677	55,722	389,008	$ 29.26	$ 27.59	$ 10,733,785	$ 1,630,245	$ 9,103,540	$ -
2/1/2018	185,608	111,924	(2,147)	2,147	185,608	114,070	$ 27.45	$ 27.10	$ 3,091,397	$ 5,094,763	$ -	$ 2,003,366
3/1/2018	99,239	207,088	(10,708)	10,708	99,239	217,796	$ 25.39	$ 26.85	$ 5,848,124	$ 2,520,017	$ 3,328,107	$ -
4/1/2018	69,221	293,408	(35,233)	35,233	69,221	328,641	$ 23.17	$ 25.03	$ 8,226,302	$ 1,603,931	$ 6,622,371	$ -
5/1/2018	198,235	80,671	(1,038)	1,038	198,235	81,709	$ 22.96	$ 24.48	$ 2,000,149	$ 4,551,323	$ -	$ 2,551,175
6/1/2018	425,134	8,312	28,028	(28,028)	453,162	8,312	$ 25.36	$ 25.27	$ 210,016	$ 11,491,970	$ -	$ 11,281,955
7/1/2018	305,665	34,178	20,181	(20,181)	325,846	34,178	$ 26.29	$ 26.13	$ 893,064	$ 8,565,587	$ -	$ 7,672,523
8/1/2018	338,633	21,545	16,953	(16,953)	355,586	21,545	$ 26.40	$ 26.18	$ 564,101	$ 9,385,780	$ -	$ 8,821,679
9/1/2018	131,534	111,886	(20,886)	20,886	131,534	132,771	$ 23.63	$ 25.60	$ 3,399,372	$ 3,107,887	$ 291,485	$ -
10/1/2018	256,072	102,325	(22,949)	22,949	256,072	125,274	$ 23.23	$ 24.56	$ 3,076,143	$ 5,947,354	$ -	$ 2,871,211
11/1/2018	394,250	27,477	(229)	229	394,250	27,707	$ 22.57	$ 24.34	$ 674,433	$ 8,897,468	$ -	$ 8,223,035
	2,706,465	1,518,614			2,771,627	1,628,921			$ 42,648,036	$ 69,558,360		

Note: Totals may not sum due to rounding

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Ward Workpaper 7
Docket No. E-2, Sub 1146

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales
Billing Period December 2017 - November 2018

Fall 2016 Forecast

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC			
Residential	15,667,933		15,667,933
Small General Service	1,808,399		1,808,399
Medium General Service	10,417,309		10,417,309
Large General Service	9,237,571		9,237,571
Lighting	395,287		395,287
Total	37,526,498		37,526,498
SC Retail	6,464,060	20,522	6,484,582
Total Wholesale	18,173,258		18,173,258
Total Adjusted NC System Sales	62,163,816	20,522	62,184,338
NC as a percentage of total	60.37%	0.00%	60.35%
SC as a percentage of total	10.40%	100.00%	10.43%
Wholesale as a percentage of total	29.23%	0.00%	29.22%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		20,522	
Marginal Fuel rate per MWh for SC NEM	$	32.02	
Fuel Benefit to be directly assigned to SC	$	657,114	
System Fuel Expense		1,334,487,963	Ward Exhibit 2, Schedule 1, Page 1
Fuel benefit to be directly assigned to SC Retail	$	657,114	
Total Adjusted System Fuel Expense		1,335,145,078	

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Normalized Sales
Billing Period December 2017 - November 2018

Fall 2016 Forecast

	Test Period Sales MWhs	Weather Normalization	Customer Growth	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC					
Residential	15,187,842	523,428	75,104		15,786,375
Small General Service	1,880,312	7,530	8,915		1,896,757
Medium General Service	11,128,006	15,745	18,643		11,162,395
Large General Service	8,348,171	0	(800)		8,347,370
Lighting	376,840	0	297		377,137
Total	36,921,171	546,703	102,158		37,570,033
SC Retail	6,252,503	65,248	(5,128)	20,522	6,333,145
Total Wholesale	17,799,446	175,343	78,202		18,052,991
Total Adjusted NC System Sales	60,973,121	787,295	175,232	20,522	61,956,170
NC as a percentage of total	60.55%				60.64%
SC as a percentage of total	10.25%				10.22%
Wholesale as a percentage of total	29.19%				29.14%

SC Net Metering allocation adjustment		20,522
Total Projected SC NEM MWhs	$	32.02
Marginal Fuel rate per MWh for SC NEM	$	657,114
Fuel Benefit to be directly assigned to SC		
System Fuel Expense	$	1,326,771,851 Ward Exhibit 2, Schedule 2, page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$	657,114
Total Adjusted System Fuel Expense	$	1,327,428,966

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales - NERC 5 year Average
Billing Period December 2017 - November 2018

Fall 2016 Forecast

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC			
Residential	15,667,933		15,667,933
Small General Service	1,808,399		1,808,399
Medium General Service	10,417,309		10,417,309
Large General Service	9,237,571		9,237,571
Lighting	395,287		395,287
Total	37,526,498		37,526,498
SC Retail	6,464,060	20,522	6,484,582
Total Wholesale	18,173,258		18,173,258
Total Adjusted NC System Sales	62,163,816	20,522	62,184,338
NC as a percentage of total	60.37%	0.00%	60.35%
SC as a percentage of total	10.40%	100.00%	10.43%
Wholesale as a percentage of total	29.23%	0.00%	29.22%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs		20,522	
Marginal Fuel rate per MWh for SC NEM	$	32.02	
Fuel Benefit to be directly assigned to SC	$	657,114	
System Fuel Expense		1,363,448,628	Ward Exhibit 2, Schedule 3, Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$	657,114	
Total Adjusted System Fuel Expense		1,364,105,743	

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
NC Retail Allocation %
Energy Allocation Factors - 12 Months Ending December 31, 2016

	kWh @ Meter	E-2 Allocation	kWh @ Prod Out.	E-1 Allocation
NC RES	14,955,078,703	0.241916	15,673,964,377	0.244874
NC RES-TOU	530,252,474	0.008577	555,741,535	0.008682
NC SGS	1,867,042,693	0.030202	1,956,769,122	0.030571
NC SGS-CLR	27,248,688	0.000441	28,558,523	0.000446
NC MGS-TOU	8,328,878,650	0.134730	8,709,716,316	0.136072
NC MGS	2,776,099,446	0.044907	2,906,002,340	0.045400
NC SI	53,055,810	0.000858	55,319,531	0.000864
NC LGS	1,163,676,080	0.018824	1,208,152,228	0.018875
NC LGS-TOU	1,652,031,867	0.026724	1,715,476,301	0.026801
NC LGS-RTP	5,530,306,132	0.089459	5,706,315,125	0.089150
NC TSS	5,644,587	0.000091	5,915,920	0.000092
NC ALS	287,838,376	0.004656	301,674,671	0.004713
NC SLS	94,141,077	0.001523	98,666,407	0.001541
NC SFLS	1,182,005	0.000019	1,228,214	0.000019
Total NCR	37,272,476,588	0.602927	38,923,500,611	0.608102
NCEMPA	7,509,347,527	0.121473	7,622,551,599	0.119087
NCEMC	7,490,870,018	0.121174	7,603,795,540	0.118794
Fayetteville	2,124,305,706	0.034363	2,156,329,801	0.033688
FBEMC	521,138,575	0.008430	528,994,785	0.008264
Piedmont EMC	69,227,990	0.001120	70,271,608	0.001098
Haywood EMC	77,865,435	0.001260	79,039,263	0.001235
Tri-Towns	75,326,175	0.001218	76,461,724	0.001195
Waynesville	94,190,878	0.001524	95,610,814	0.001494
Winterville	53,170,188	0.000860	53,971,733	0.000843
Total NCWHS	10,506,094,965	0.169949	10,664,475,266	0.166611
Total NC	55,287,919,080	0.894348	57,210,527,476	0.893800
SC RES	2,056,757,035	0.033271	2,155,624,664	0.033677
SC RET	44,606,572	0.000722	46,750,795	0.000730
SC SGS	278,815,598	0.004510	292,196,484	0.004565
SC SGS-CLR	2,099,640	0.000034	2,200,569	0.000034
SC MGS-TOU	1,119,620,534	0.018111	1,170,489,224	0.018287
SC MGS	541,530,905	0.008760	566,356,207	0.008848
SC SI	14,177,976	0.000229	14,772,712	0.000231
SC LGS	687,597,989	0.011123	713,488,542	0.011147
SC LGS-TOU	258,339,688	0.004179	267,125,857	0.004173
SC LGS-CRTL-TOU	647,021,801	0.010466	665,028,290	0.010390
SC LGS-RTP	589,087,457	0.009529	604,506,079	0.009444
SC TSS	855,612	0.000014	896,741	0.000014
SC ALS	74,626,094	0.001207	78,213,346	0.001222
SC SLS	17,986,079	0.000291	18,850,664	0.000295
SC SFLS	144,007	0.000002	149,637	0.000002
Total SCR	6,333,266,987	0.102448	6,596,649,811	0.103059
SCWHS (Camden)	198,052,542	0.003204	201,038,202	0.003141
Total SC	6,531,319,529	0.105652	6,797,688,012	0.106200
Total System	61,819,238,609	1.000000	64,008,215,488	1.000000

2016 Cost of Service Data

	kWh @ Meter	kWh @ Prod Out.	Losses (kWh)	Loss Percent
Residential	15,485,331,177	16,229,705,911	744,374,734	4.81%
SGS	1,899,935,968	1,991,243,566	91,307,598	4.81%
MGS	11,158,033,906	11,671,038,187	513,004,281	4.60%
LGS	8,346,014,079	8,629,943,654	283,929,575	3.40%
Lighting	383,161,458	401,569,293	18,407,835	4.80%
Total NC Retail	37,272,476,588	38,923,500,611	1,651,024,023	4.43%
Total NC Retail	37,272,476,588	38,923,500,611	1,651,024,023	4.43%
SC Retail	6,333,266,987	6,596,649,811	263,382,824	
NEM Generation	212,484	221,707	9,223	
	6,333,479,471	6,596,871,517	263,392,047	4.16%
All other jurisdications	18,213,282,551	18,487,843,361	274,560,810	1.51%
Total System	61,819,238,609	64,008,215,488	2,188,976,879	3.54%

Line Loss Calculations for Projected Fuel Costs

	MWh @ Meter	MWh @ Prod Out.	Losses (MWh)	Loss Percent
Total NC Retail	37,526,498	39,265,819	1,739,321	4.63%
Total SC Retail	6,484,582	6,765,960	281,378	4.34%
All other jurisdications	18,173,258	18,451,409	278,151	1.53%
Total System	62,184,338	64,483,187	2,298,849	3.70%
Allocation percent - NC retail	60.35%	60.89%		

Line Loss Calculations for Normalized Test Period Sales

	MWh @ Meter	MWh @ Prod Out.	Losses (MWh)	Loss Percent
Total NC Retail	37,570,033	39,311,372	1,741,339	4.63%
Total SC Retail	6,333,145	6,607,952	274,807	4.34%
All other jurisdications	18,052,991	18,329,301	276,310	1.53%
Total System	61,956,170	64,248,625	2,292,455	3.70%
Allocation percent - NC retail	60.64%	61.19%		

										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 Dec. 2017 DSM/EE Rate (11) per RMCRY14	Opt-Out Credit Due to Jan. 2017 DSM/EE Rate (12) per RMCRY15	REPS Revenue Due to December 2016 Rate Change (13) per RMCRY10	REPS Revenue Due to February 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 1/17 EE Rate (17) = (3) * Rate Change	Annual Opt-Out Impact of 1/17 EE Rate (18) = (4) * Rate Change	Annual Impact of Feb. 2015 REPS Rate (19) = (8) * Rate Change	Annual Revenue At Current Rates (20)=(15)+[16-17-18]+(19)
Residential		15,259,144,792	0	0	14,296,062	15,259,144,792	0	14,195,803	$1,618,944,980	($27,940,555)	$0	$0	$558,031	($34,141)	$1,646,361,645	($60,766,886)	$0	$0	$1,703,496	$1,587,298,255
	Residential	15,187,836,703	0	0	14,182,100	15,187,836,703	0	14,116,875	$1,597,089,504	($27,619,946)	$0	$0	$554,932	($33,954)	$1,624,188,471	($59,588,870)	$0	$0	$1,694,025	$1,566,293,626
	SGS	2,127	0	0	9	2,127	0	4	$284	($15)	$0	$0	$1	($0)	$299	($16)	$0	$0	$1	$284
	MGS	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
	Lighting	71,305,962	0	0	113,953	71,305,962	0	78,924	$21,855,192	($320,593)	$0	$0	$3,099	($187)	$22,172,874	($1,178,000)	$0	$0	$9,471	$21,004,345
Commercial		12,293,968,344	3,891,136,612	3,926,584,051	2,404,235	2,142,098,614	29,987,294	2,301,683	$1,051,170,871	($18,279,041)	$324,329	$73,530	$2,682,536	($33,269)	$1,067,198,504	($66,239,288)	$2,094,073	$469,708	$9,206,732	$1,007,602,168
	Residential	2,441	0	0	12	2,441	0	0	$269	($1)	$0	$0	($7)	$0	$277	($13)	$0	$0	$0	$264
	SGS	1,856,601,823	13,305,277	13,682,969	1,956,309	1,856,601,823	0	1,761,968	$207,364,080	($3,827,254)	$1,240	$291	$2,051,219	($25,470)	$209,167,116	($13,699,631)	$7,185	$1,642	$7,047,873	$202,506,531
	MGS	9,065,677,807	2,814,279,857	2,855,437,257	434,064	60,611,049	27,801,344	391,825	$712,075,299	($13,283,570)	$239,079	$54,660	$458,054	($5,648)	$725,200,202	($48,274,175)	$1,519,711	$342,652	$1,567,300	$676,630,963
	LGS	1,146,802,972	1,051,448,008	1,045,112,908	1,103	0	2,185,950	964	$82,045,368	($992,875)	$84,111	$18,579	$1,194	($13)	$83,139,751	($3,764,743)	$567,782	$125,414	$3,857	$78,685,669
	Lighting	224,883,301	12,103,470	12,350,917	12,747	224,883,301	0	146,926	$49,685,856	($175,341)	($101)	$0	$172,076	($2,139)	$49,691,159	($500,725)	($605)	$0	$587,702	$49,778,742
Industrial		7,899,191,539	7,255,083,388	7,290,779,217	42,546	35,074,733	16,691,182	24,035	$500,962,301	($8,613,489)	$559,005	$124,952	$153,457	($352)	$510,106,642	($30,438,995)	$3,912,749	$873,830	$537,182	$475,418,250
	Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SGS	18,833,973	7,679,733	7,694,456	12,316	18,833,973	0	3,862	$1,933,055	($41,885)	$700	$156	$25,001	($57)	$1,950,852	($137,427)	$4,147	$923	$86,307	$1,894,662
	MGS	2,062,322,077	1,394,871,433	1,416,141,059	27,688	444,519	5,984,685	16,432	$154,694,439	($3,074,755)	$121,816	$27,498	$104,647	($243)	$157,814,104	($10,988,029)	$753,231	$169,937	$367,251	$146,270,158
	LGS	5,802,239,248	5,844,064,420	5,858,079,429	2,334	0	10,706,497	1,791	$341,602,738	($5,423,550)	$436,561	$97,298	$11,758	($26)	$347,548,415	($19,052,584)	$3,155,795	$702,970	$40,040	$324,677,107
	Lighting	15,796,241	8,467,802	8,864,273	208	15,796,241	0	1,950	$2,732,069	($73,299)	($72)	$0	$12,051	($27)	$2,793,271	($260,955)	($423)	$0	$43,584	$2,576,323
Public Streets & Highways		69,733,462	0	0	11,909	69,733,462	0	11,026	$16,991,216	($305,519)	$0	$0	$11,918	($138)	$17,284,955	($1,106,137)	$0	$0	$44,104	$16,222,922
	Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SGS	4,880,962	0	0	6,286	4,880,962	0	6,180	$422,112	($9,480)	$0	$0	$6,260	($68)	$425,401	($36,857)	$0	$0	$24,720	$413,264
	MGS	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
	Lighting	64,852,500	0	0	5,623	64,852,500	0	4,846	$16,569,103	($296,039)	$0	$0	$5,658	($70)	$16,859,554	($1,069,279)	$0	$0	$19,384	$15,809,658
Military		1,398,562,548	1,405,377,858	1,405,377,858	48	1,920	2,712,427	48	$81,318,739	($1,092,775)	$55,062	$12,236	$273	($1)	$82,478,540	($4,589,851)	$758,904	$168,645	$1,073	$76,962,212
	Residential	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
	MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	LGS	1,398,560,628	1,405,377,858	1,405,377,858	48	0	2,712,427	48	$81,318,515	($1,092,767)	$55,062	$12,236	$273	($1)	$82,478,307	($4,589,820)	$758,904	$168,645	$1,073	$76,962,011
	Lighting	1,920	0	0	0	1,920	0	0	$225	($8)	$0	$0	$0	$0	$232	($32)	$0	$0	$0	$201
NC Retail		36,920,600,685	12,551,597,858	12,622,741,126	16,754,800	17,506,053,521	49,390,903	16,532,595	$3,269,388,108	($56,231,380)	$938,396	$210,718	$3,406,216	($67,900)	$3,323,430,286	($163,141,157)	$6,765,726	$1,512,183	$11,492,587	$3,163,503,807
Rate Schedules (excludes REPS)																				
RES (includes RES-RECD)		14,677,357,246	0	0	13,879,986	14,677,357,246	0		$1,550,712,883	($26,779,041)	$0	$0	$554,925		$1,576,936,999	($63,031,586)	$0	$0		$1,513,905,413
SGS		1,844,617,775	20,985,010	21,377,425	1,898,068	1,844,617,775	0		$205,767,389	($3,808,250)	$1,940	$447	$1,996,319		$207,581,706	($13,631,391)	$11,332	$2,565		$193,936,417
MGS		2,733,350,508	316,004,450	314,051,716	197,424	0	13,101,560		$259,402,209	($4,066,340)	$28,837	$6,479	$247,803		$263,256,062	($14,304,019)	$170,642	$37,686		$248,743,715
SGS-TOU		8,310,771,868	3,885,895,118	3,950,272,478	252,552	0	20,631,142		$598,807,216	($12,223,538)	$331,647	$75,587	$305,462		$611,132,526	($44,402,275)	$2,098,383	$474,033		$564,157,834
LGS		1,157,924,718	1,036,476,045	1,050,491,054	1,180	0	2,599,630		$87,985,002	($1,021,463)	$78,007	$17,620	$4,664		$89,097,428	($3,785,668)	$559,697	$126,059		$84,626,004
LGS-TOU		1,675,614,055	1,634,264,346	1,627,929,246	1,418	0	2,946,731		$115,474,077	($1,555,076)	$142,581	$31,573	$3,937		$117,199,369	($5,503,674)	$882,503	$195,352		$110,617,841
LGS-RTP		95,201	326,200	326,200	6	0	10,192		$259,085	$0	$0	$0	$67		$259,018	($12)	$176	$39		$258,790
LGS-RTP-TOU		5,513,968,874	5,629,823,695	5,629,823,695	881	0	10,048,321		$301,248,457	($4,932,653)	$355,146	$78,921	$4,558		$306,610,620	($18,117,792)	$3,040,105	$675,579		$284,777,144
LGS Class		8,347,602,848	8,300,890,286	8,308,570,195	3,485	0	15,604,874		$504,966,621	($7,509,192)	$575,734	$128,114	$13,226		$513,166,435	($27,407,147)	$4,482,481	$997,028		$480,279,779
<u>Rate Class</u>																				
Residential		15,187,839,144	0	0	14,182,112	15,187,839,144	0	14,116,875	$1,597,089,773	($27,619,947)	$0	$0	$554,925	($33,954)	$1,624,188,748	($59,588,883)	$0	$0	$1,694,025	$1,566,293,890
SGS		1,880,318,885	20,985,010	21,377,425	1,974,920	1,880,318,885	0	1,772,014	$209,719,532	($3,878,636)	$1,940	$447	$2,082,481	($25,595)	$211,543,668	($13,873,932)	$11,332	$2,565	$7,158,901	$204,814,740
MGS		11,127,999,884	4,209,151,290	4,271,578,316	461,752	61,055,568	33,786,029	408,257	$866,769,738	($16,358,325)	$360,895	$82,157	$562,701	($5,890)	$883,014,306	($59,262,204)	$2,272,942	$512,589	$1,934,551	$822,901,121
LGS		8,347,602,848	8,300,890,286	8,308,570,195	3,485	0	15,604,874	2,804	$504,966,621	($7,509,192)	$575,734	$128,114	$13,226	($39)	$513,166,474	($27,407,147)	$4,482,481	$997,028	$44,969	$480,324,787
Lighting		376,839,924	20,571,272	21,215,190	132,531	376,839,924	0	232,646	$90,842,444	($865,280)	($173)	$0	$192,884	($2,422)	$91,517,090	($3,008,991)	($1,029)	$0	$660,141	$89,169,269
		36,920,600,685	12,551,597,858	12,622,741,126	16,754,800	17,506,053,521	49,390,903	16,532,595	$3,269,388,108	($56,231,380)	$938,396	$210,718	$3,406,216	($67,900)	$3,323,430,286	($163,141,157)	$6,765,726	$1,512,183	$11,492,587	$3,163,503,807

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Adjustment - MWh
Twelve Months Ended March 31, 2017

Residential Weather Adjustment MWh

	North Carolina				South Carolina				
	R2 All Electric	R3 Water Heating	R4 Minimum Use	Total	R2 All Electric	R3 Water Heating	R4 Minimum Use	Total	System Total
Apr-16	41,654	15,967	1,736	59,358	16,242	2,538	1,242	20,023	79,381
May-16	42,888	12,817	14,302	70,007	183	31	14	229	70,235
Jun-16	44,584	16,264	14,794	75,642	(6,407)	(1,080)	(1,129)	(8,616)	67,027
Jul-16	73,175	26,634	24,306	124,115	(13,746)	(4,660)	(2,292)	(20,698)	103,417
Aug-16	(58,054)	(21,118)	(19,332)	(98,504)	(18,042)	(6,170)	(2,745)	(26,957)	(125,461)
Sep-16	(107,339)	(38,943)	(35,964)	(182,246)	(19,372)	(6,474)	(3,376)	(29,223)	(211,468)
Oct-16	(65,051)	(5,463)	(21,664)	(92,177)	(3,314)	(2,413)	(1,206)	(6,933)	(99,111)
Nov-16	34,706	12,645	1,311	48,662	10,700	2,176	1,029	13,904	62,566
Dec-16	15,833	2,658	1,721	20,211	8,618	1,130	721	10,468	30,679
Jan-17	128,352	22,731	21,021	172,103	32,993	5,460	2,720	41,172	213,275
Feb-17	216,154	36,216	4,531	256,902	41,024	6,653	3,421	51,098	308,000
Mar-17	54,191	15,345	(181)	69,355	18,744	1,099	1,910	21,754	91,109
Total	**421,093**	**95,753**	**6,582**	**523,428**	**67,623**	**(1,710)**	**309**	**66,222**	**589,650**

Commercial	**22,301**
Wholesale	**175,343**
Total NC System	**787,295**

Commercial Weather Adjustment MWh

	NC	SC	System
Apr-16	8,547	3,726	12,273
May-16	22,425	(1,628)	20,796
Jun-16	31,652	(4,398)	27,254
Jul-16	41,938	(7,019)	34,919
Aug-16	(15,536)	(5,886)	(21,421)
Sep-16	(29,468)	(9,903)	(39,372)
Oct-16	(41,296)	(8,513)	(49,809)
Nov-16	(4,250)	(1,515)	(5,765)
Dec-16	1,530	2,546	4,076
Jan-17	35,372	11,075	46,447
Feb-17	44,008	14,172	58,180
Mar-17	(71,646)	6,370	(65,277)
Total	**23,275**	**(974)**	**22,301**

Wholesale Weather Adjustment MWH

	MWH
Apr-16	(72,414)
May-16	54,046
Jun-16	66,154
Jul-16	49,033
Aug-16	(170,875)
Sep-16	(203,473)
Oct-16	26,961
Nov-16	163,807
Dec-16	114,840
Jan-17	120,199
Feb-17	24,470
Mar-17	2,594
Total	**175,343**

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adustment - MWh
Twelve Months Ended March 31, 2017

Rate Schedule	Reference	NC Proposed KWH [1] Adjustment	SC Proposed KWH Adjustment	Wholesale Proposed KWH Adjustment
Residential	RES	75,104,150	615,058	
General:				
General Service Small	SGS	8,915,017	(127,993)	
General Service Medium	MGS	18,642,770	(5,980,197)	
Total General		27,557,787	(6,108,190)	
Lighting:				
Street Lighting	SLS/SLR	554,334	369,541	
Sports Field Lighting	SFLS	19,960	(16,137)	
Traffic Signal Service	TSS/TFS	(277,535)	13,368	
Total Street Lighting		296,759	366,772	
Industrial:				
I - Textile	LGS	-	(1,503)	
I - Nontextile	LGS	(800,431)	-	
Total Industrial		(800,431)	(1,503)	
Total		**102,158,265**	**(5,127,863)**	**78,202,031**

[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 2017 - November 2018

($)

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 $
12/1/17	$ 356,272	$ 915,158	(18,567.22)	$ 595,847	$ 306,513	$ 116,522	$ 2,271,744	$ 29,851	$ (11,283)	$ 2,290,312
1/1/18	$ 616,327	$ 1,524,922	(63,408.66)	$ 595,847	$ 502,998	$ 207,198	$ 3,383,883	$ (32,112)	$ (23,039)	$ 3,328,733
2/1/18	$ 338,730	$ 880,980	(61,884.74)	$ 595,847	$ 287,337	$ 108,039	$ 2,149,047	$ (37,503)	$ (15,012)	$ 2,096,532
3/1/18	$ 130,478	$ 425,662	(11,421.76)	$ 595,847	$ 78,347	$ 30,956	$ 1,249,867	$ 66,451	$ (3,377)	$ 1,312,942
4/1/18	$ 93,631	$ 277,627	(4,579.80)	$ 595,847	$ 75,362	$ 24,918	$ 1,062,806	$ 7,973	$ (3,868)	$ 1,066,911
5/1/18	$ 105,328	$ 381,522	(4,389.19)	$ 595,847	$ 61,685	$ 21,288	$ 1,161,280	$ 70,148	$ (2,847)	$ 1,228,580
6/1/18	$ 412,744	$ 1,200,157	(20,153.44)	$ 595,847	$ 360,734	$ 145,051	$ 2,694,379	$ (32,891)	$ (16,553)	$ 2,644,935
7/1/18	$ 532,966	$ 1,559,267	(18,979.47)	$ 595,847	$ 442,159	$ 187,946	$ 3,299,205	$ (66,508)	$ (21,294)	$ 3,211,403
8/1/18	$ 516,576	$ 1,538,320	(13,223.06)	$ 595,847	$ 432,802	$ 184,464	$ 3,254,786	$ (81,203)	$ (20,884)	$ 3,152,698
9/1/18	$ 159,280	$ 503,639	(8,481.30)	$ 595,847	$ 129,444	$ 48,041	$ 1,427,770	$ (14,056)	$ (6,956)	$ 1,406,758
10/1/18	$ 85,864	$ 303,778	(6,873.27)	$ 595,847	$ 53,706	$ 21,416	$ 1,053,737	$ 27,949	$ (2,962)	$ 1,078,724
11/1/18	$ 73,860	$ 307,966	(13,122.89)	$ 595,847	$ 36,762	$ 10,296	$ 1,011,608	$ 72,295	$ (1,528)	$ 1,082,375
Total	$ 3,422,057	$ 9,818,996	$ (245,085)	$ 7,150,158	$ 2,767,850	$ 1,106,136	$ 24,020,113	$ 10,393	$ (129,602)	$ 23,900,904

Note: Totals may not sum due to rounding

Ward Workpaper 13
Docket No. E-2, Sub 1146

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2% Calculation Test
Billing Period December 2017 - November 2018

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 148,740,646	$ 63,374,757	$ 212,115,403
2	Amount in 2016 Filing: Docket E-2 Sub 1107[1]	$ 139,579,315	$ 5,505,223	$ 145,084,538
3	Increase/(Decrease)	$ 9,161,331	$ 57,869,534	$ 67,030,865
4	2% of 2016 NC revenue of $3,375,847,367			$ 67,516,947

[1] From Revised McGee Workpaper 13 from E-2, Sub 1107 Supplemental filing

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases Total	$ 41,519,620	60.35%	$ 25,057,091
WP 4	Renewables Energy	$ 154,215,192	60.35%	$ 93,068,869
WP 4	Renewables Capacity	$ 31,684,006	59.73%	$ 18,925,807
WP 4	Other purchase info not in model*	$ 19,368,483	60.35%	$ 11,688,879
	Total	$ 246,787,301		$ 148,740,646

* Allocated Economic Purchases, Excludes JDA Transfer purchases and Savings

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2% Calculation Test-Detail Calculation
Test Period April 2017 - March 2018

Line No.		Reference	Apr'16	May'16	Jun'16	July'16	Aug'16	Sept'16	Oct'16	Nov'16	Dec'16	Jan'17	Feb'17	Mar'17	12ME
1	System kWh Sales, at generation	Schedule 4 (Line 3)	4,368,389,684	4,551,986,863	5,494,831,309	6,359,393,524	6,815,099,338	5,930,560,119	4,672,388,697	4,541,469,093	5,077,570,348	5,837,954,277	4,712,196,051	4,811,729,205	63,173,568,507
2	NC Retail kWh Sales, at generation	Schedule 4(Line 4c)	2,713,691,694	2,737,761,490	3,288,043,085	3,701,934,098	4,094,182,983	3,766,769,530	2,986,058,625	2,692,796,058	2,999,971,469	3,602,229,624	2,983,145,960	2,967,909,164	38,534,493,780
3	NC Retail % of Sales	Line 2 / Line 1	62.12%	60.14%	59.84%	58.21%	60.08%	63.51%	63.91%	59.29%	59.08%	61.70%	63.31%	61.68%	61.00%
	Total Purchase Power, Excl. JDA														
4	System Purchase Power, incl. Renewable & Excl. JDA		$ 18,867,513	$ 18,914,330	$ 19,068,582	$ 28,129,907	$ 26,422,347	$ 24,304,626	$ 17,010,938	$ 23,996,269	$ 17,866,465	$ 16,070,443	$ 16,291,274	$ 31,028,099	$ 257,970,796
5	NC Purchase Power	Line 4 * Line 3	$ 11,720,707	$ 11,375,895	$ 11,410,418	$ 16,374,999	$ 15,873,272	$ 15,436,978	$ 10,871,454	$ 14,228,228	$ 10,556,010	$ 9,916,047	$ 10,313,503	$ 19,138,355	$ 157,215,865
6	NC Retail kWh Sales	Sch. 4 (Line 4a)	2,600,934,958	2,623,854,707	3,150,542,583	3,546,318,104	3,921,804,085	3,608,731,774	2,862,105,988	2,581,057,175	2,873,976,261	2,873,976,261	2,858,254,851	2,843,638,718	36,345,195,465
7	Incurred Rate	Line 5 / Line 6 * 100	0.451	0.434	0.362	0.462	0.405	0.428	0.380	0.551	0.367	0.345	0.361	0.673	0.433
	Total Capacity														
8	System Capacity		$ 3,370,446	$ 3,084,170	$ 2,414,562	$ 5,051,623	$ 3,909,640	$ 4,694,923	$ 2,264,828	$ 1,207,168	$ 2,762,140	$ 1,669,052	$ 2,516,521	$ 3,091,243	$ 36,036,316
9	NC Capacity	Capacity*.6315	$ 2,128,437	$ 1,947,653	$ 1,524,796	$ 3,190,100	$ 2,468,937	$ 2,964,844	$ 1,430,239	$ 762,327	$ 1,744,291	$ 1,054,006	$ 1,589,183	$ 1,952,120	$ 22,756,934
10	NC Retail kWh Sales	Line 6	2,600,934,958	2,623,854,707	3,150,542,583	3,546,318,104	3,921,804,085	3,608,731,774	2,862,105,988	2,581,057,175	2,873,976,261	2,873,976,261	2,858,254,851	2,843,638,718	36,345,195,465
11	Incurred Rate	Line 12/Line 13*100	0.082	0.074	0.048	0.090	0.063	0.082	0.050	0.030	0.061	0.037	0.056	0.069	0.063
12	Total Incurred Rate (Purchased Power, Renewable Energy + Capacity)	Line 7 + Line 11	0.532	0.508	0.411	0.552	0.468	0.510	0.430	0.581	0.428	0.382	0.416	0.7416721	0.495
13	Billed Rate	Billed Rates Below	0.303	0.303	0.303	0.303	0.303	0.303	0.303	0.303	0.330	0.365	0.370	0.3701523	
14	Over/(Under) cents per kwh	Line 13 - Line 12	(0.229)	(0.204)	(0.107)	(0.248)	(0.164)	(0.207)	(0.126)	(0.277)	(0.098)	(0.017)	(0.046)	(0.371520)	
15	Over/(Under) $	Line 14 * Line10 /100	(5,959,563)	(5,364,444)	(3,378,473)	(8,807,828)	(6,445,953)	(7,455,227)	(3,619,885)	(7,161,271)	(2,807,445)	(487,198)	(1,322,790)	(10,564,680)	(63,374,757)

	Billed Rate from Docket E-2, Sub 1069 - Apr'16-Nov'16		
16	Purchases (Other Purchases + Economic Purchases)	61,596,550	McGee Supplemental Workpaper 4 + 5
17	MWH Sales	62,510,062	McGee Supplemental Workpaper 3
18	Billed Rate for Purchases	**0.099**	
19	Renewables	106,255,915	McGee Supplemental Workpaper 4
20	MWH Sales	62,510,062	McGee Supplemental Workpaper 3
21	Billed Rate for Renewables	**0.170**	
22	Capacity	21,763,259	McGee Settlement Exhibit 2, Schedule 2 (Not officially filed)
23	MWH Sales	62,510,062	McGee Supplemental Workpaper 3
24	Billed Rate for Capacity	**0.035**	
25	Total Billed Rate	**0.303**	
	Billed Rate from Docket E-2, Sub 1107 - Dec'16-Mar'17		
26	Purchases (Other Purchases + Economic Purchases)	60,801,776	McGee Workpaper 4 + 5
27	MWH Sales	62,219,566	McGee Workpaper 3
28	Billed Rate for Purchases	**0.098**	
29	Renewables	140,601,055	McGee Workpaper 4
30	MWH Sales	62,219,566	McGee Workpaper 3
31	Billed Rate for Renewables	**0.226**	
32	Capacity	28,904,344	Revised McGee Exhibit 2, Schedule 2
33	MWH Sales	62,219,566	McGee Workpaper 3
34	Billed Rate for Capacity	**0.046**	
35	Total Billed Rate	**0.370**	

*** December billed Rate is based on prorated billing factors**	
Prior Bill Rate (Sub 1069)	0.303
Ratios of Days to rate	59.64%
Prorated Rate	**0.181**
New Bill Rate (Sub 1107)	0.370
Ratios of Days to rate	40.36%
Prorated Rate	**0.149**
Total Blended Rate for December	**0.330**

**** January billed Rate is based on prorated billing factors**	
Prior Bill Rate (Sub 1069)	0.303
Ratios of Days to rate	8.08%
Prorated Rate	**0.025**
New Bill Rate (Sub 1107)	0.370
Ratios of Days to rate	91.92%
Prorated Rate	**0.340**
Total Blended Rate for January	**0.365**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1146

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am employed as Managing Director, Fuel Procurement, for Duke Energy Corporation ("Duke Energy"). In that capacity, I directly manage the organization responsible for the purchase and delivery of coal, natural gas, and fuel oil to Duke Energy's regulated generation fleet, including Duke Energy Progress, LLC ("Duke Energy Progress," "DEP," or the "Company") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Utilities," or the "Companies"). In addition to fuels, I also supervise the procurement of all reagents and emissions.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

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

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

A. Yes. In May of 2017, I adopted the testimony filed by Swati V. Daji in support of DEC's 2016 fuel and fuel-related cost recovery application in Docket No. E-7, Sub 1129.

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 fossil fuel costs for the period April 1, 2016 through March 31, 2017 ("test period") versus April 1, 2015 through March 31, 2016 ("prior test period"), and describe changes forthcoming for the period December 1, 2017 through November 30, 2018 ("billing period"). I also provide an update on the status of guaranteed merger fuel-related savings that – pursuant to the merger agreement between Duke Energy and Progress Energy, Inc. ("Merger") – Duke Energy is delivering to its North Carolina and South Carolina customers.

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 Phipps Exhibit 1 which summarizes the Company's Fossil Fuel Procurement Practices, Phipps Exhibit 2 which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases for the test period and the prior test period, and Phipps Exhibit 3 which summarizes the fuels related transactional activity between DEC and Piedmont Natural Gas Company, Inc. ("Piedmont") for spot commodity transactions during the test period, as required by the Merger Agreement between Duke Energy and Piedmont, of which DEP receives an allocated portion based on its pro rata share of the overall gas plant burns for the respective month.

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 available 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, estimated 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 order to determine the most economic and reliable means of serving their 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 $80.26 per ton, compared to $80.74 per ton in the prior test period, representing a decrease of approximately 1%. This includes an average transportation cost of $28.03 per ton in the test period, compared to $24.02 per ton in the prior test period, representing an increase of 17%. The Company's average price of gas purchased for the test period was $4.00 per Million British Thermal Units ("MMBtu"), compared to $4.10 per MMBtu in the prior test period, representing a decrease of 2%. The cost of gas includes gas supply, transportation, storage and financial hedging.

DEP's coal burn for the test period was 4.7 million tons, compared to a coal burn of 4.8 million tons in the prior test period, representing a decrease of 3%. The Company's natural gas burn for the test period was 170.0 MMBtu, compared to a gas burn of 176.0 MMBtu in the prior test period, representing a decrease of 4%.

The differences result primarily from changes in weather driven demand and commodity prices coupled with strong performance by the Company's nuclear fleet.

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 combined with installation of new combined cycle ("CC") generation by utilities, especially in the Southeast, which has also lowered overall coal demand; (3) continued changes in demand for global markets for both steam and metallurgical coal; (4) uncertainty surrounding regulations for mining operations; and (5) the on-going financial viability of many of the Company's coal suppliers.

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, increase efficiencies, and lower production costs. In the shorter term, natural gas prices are reflective of the dynamics between supply and demand factors, such as seasonal weather and overall storage inventory balances. Over the longer term planning horizon, natural gas supply is projected to continue to increase along with the needed pipeline infrastructure to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico.

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

A. DEP's current coal burn projection for the billing period is 3.7 million tons compared to 4.7 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from factors such as delivered natural gas prices versus the average delivered cost of coal, volatile power prices, and electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $78.96 per ton for the billing period compared to $80.26 per ton in the test period. This cost, however, is subject to change based on factors such as: (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 efforts of which can be passed on through coal contracts.

DEP's current natural gas burn projection for the billing period is approximately 147.0 MMBtu, which is a decrease from the 170.0 MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $3.01 per MMBtu, compared to $2.77 per MMBtu in the test period. Projected burn volumes will vary based on factors such as changes in commodity prices 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. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company expects to address any spot and long-term coal requirements throughout this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels.

The Company has implemented natural gas procurement practices that include periodic Requests for Proposals and short-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply that includes 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 natural gas hedging plan to manage fuel cost risk for customers through a disciplined, structured execution approach. DEP continues to monitor and make adjustments as necessary to its natural gas hedging program.

Q. PLEASE PROVIDE AN UPDATE ON THE STATUS OF THE GUARANTEED MERGER FUEL-RELATED SAVINGS THE COMPANY HAS ACHIEVED THUS FAR FOR ITS RETAIL CUSTOMERS.

A. During September 2016, the Utilities met the guaranteed merger savings target of $721.8 million established pursuant to both the merger agreement between Duke Energy and Progress Energy, Inc., and the merger agreement between Duke Energy and Piedmont Natural Gas Company, Inc. The combined merger savings through September totaled $723 million, of which DEP's North Carolina share was $183 million.

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

A. Yes, it does.

Duke Energy Carolinas, 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; 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 ascertain 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, 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 2017 & 2016
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
1	April 2016	243,140	0	243,140
2	May	240,749	0	240,749
3	June	251,139	0	251,139
4	July	367,433	0	367,433
5	August	496,536	0	496,536
6	September	505,889	0	505,889
7	October	392,494	41	392,535
8	November	525,819	0	525,819
9	December	494,298	12,899	507,197
10	January 2017	319,044	72,713	391,757
11	February	284,208	29,067	313,275
12	March	191,908	13,396	205,304
13	**Total** (Sum L1:L12)	**4,312,657**	**128,116**	**4,440,773**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
14	April 2015	538,920	0	538,920
15	May	499,049	0	499,049
16	June	388,031	0	388,031
17	July	497,293	0	497,293
18	August	531,402	61,083	592,485
19	September	578,888	62,257	641,145
20	October	556,881	142,145	699,026
21	November	335,613	81,620	417,233
22	December	213,630	58,536	272,166
23	January 2016	135,132	104,742	239,874
24	February	255,566	46,882	302,448
25	March	459,644	0	459,644
26	**Total** (Sum L14:L25)	**4,990,049**	**557,265**	**5,547,314**

DUKE ENERGY PROGRESS
Summary of Gas Purchases
Twelve Months Ended March 2017 & 2016
MBTUs

Line No.	Month	MBTUs
1	April 2016	14,115,727
2	May	14,616,922
3	June	14,111,918
4	July	16,564,902
5	August	17,177,486
6	September	12,559,298
7	October	9,919,151
8	November	14,384,387
9	December	13,607,974
10	January 2017	13,786,819
11	February	14,028,144
12	March	14,884,889
13	**Total** (Sum L1:L12)	**169,757,617**

Line No.	Month	MBTUs
14	April 2015	12,523,884
15	May	14,416,738
16	June	15,284,136
17	July	15,111,611
18	August	14,768,643
19	September	14,633,497
20	October	10,978,923
21	November	15,252,462
22	December	14,132,589
23	January 2016	15,130,511
24	February	16,389,046
25	March	17,697,705
26	**Total** (Sum L14:L25)	**176,319,745**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1146

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	)

BRETT PHIPPS CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

JUNE 21, 2017

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1146

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 2015 and 2016 annual fuel and fuel-related cost recovery proceedings (Docket No. E-2, Subs 1069 and 1107), as well as DEC's 2016 and 2017 annual fuel and fuel-related cost recovery proceedings (Docket No. E-7, Subs 1104 and 1129).

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 2016 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, 2016 through March 31, 2017 (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 9,288 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	3,544 MWs
Combustion Turbines -	2,887 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 34 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 2016 ANNUAL FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. The Company added the Elm City solar site with 40 MWs of nameplate capacity, providing 18 MWs of utility equivalent capacity, which brings the Company's total solar dependable capacity to 62 MWs. Sutton CT Unit 1 retired in March 2017, which reduced capacity by 11 MWs. Sutton CT Unit 2 and Unit 3 will retire in mid 2017, when the new Sutton fast start CTs come online, which will provide 84 MWs of capacity.

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 GENERATING FACILITY PROVIDE FOR THE TEST PERIOD?

A. For the test period, DEP's total system generation was 62,749,766 MW hours ("MWHs"), of which 33,716,463 MWHs, or approximately 54%, was provided by the fossil/hydro/solar fleet. The breakdown includes 35% contribution from gas facilities, 18% contribution from coal-fired stations, approximately 1% contribution from hydro and solar facilities.

The Company's portfolio includes a diverse mix of units that, along with additional nuclear capacity, allow 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 new CC units within DEP's portfolio in recent years has provided DEP with additional natural gas resources that feature state-of-the-art technology for increased efficiency, and significantly reduced emissions. These factors promote the use of natural gas and provide real benefits in cost of fuel and reduced emissions for customers. Gas fired facilities provided 65% of the DEP Fossil/Hydro/Solar generation during the review period.

Q. PLEASE EXPLAIN THE TERM "HEAT RATE" AND WHAT WAS THE HEAT RATE FOR DEP'S COAL-FIRED FLEET AND COMBINED CYCLES DURING THE TEST PERIOD?

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the test period, the seven coal units produced 33% of the fossil/hydro/solar generation. The average heat rate for the coal-fired units was 10,550 Btu/kWh. The most active station during this period was Roxboro, providing 70% of the coal production with a heat rate of 10,177 Btu/kWh.

During the test period, the four CC power blocks produced 55% of the fossil/hydro/solar generation with an average heat rate of 7,094 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 2011 through 2015. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating. Overall, the data in the chart reflects that DEP results were better than the NERC five-year comparisons.

Generator Type	Measure	Review Period DEP Operational Results	2011-2015 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	91.1%	82.5%	446
	NCF	35.8%	60.5%	
	EFOR	3.8%	7.4%	
Coal-Fired Summer Peak	EAF	93.4%	n/a	n/a
Total CC Average	EAF	86.5%	84.6%	309
	NCF	77.0%	51.6%	
	EFOR	1.56%	5.8%	
Total CT Average	EAF	89.6%	87.0%	876
	SR	98.2%	97.8%	
Hydro	EAF	92.5%	81.9%	1,141

[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 review period to inspect and maintain plant equipment.

Asheville Unit 2 had a planned outage in the fall of 2016. The primary purpose of the outage was rewinding the steam turbine generator rotor. Mayo Unit 1 had a planned outage in the fall of 2016 to repair a governor valve on the main turbine and wash both air preheaters. Roxoboro Unit 3 had a planned outage in the fall of 2016 for a minor turbine overhaul.

The CC fleet performed planned outages at Richmond County CC PB4 and PB5 in the fall of 2016. The primary purpose of the PB4 outage was rewinding the steam turbine generator rotor and to perform a hot gas path inspection on the combustion turbines. The primary purpose of the PB5 outage was to perform boroscope inpections on both combustion turbines and perform balance of plant maintenance. Also the HF Lee CC performed a hot gas path inspection in the fall of 2016.

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 1146

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**T. PRESTON GILLESPIE, 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 T. Preston Gillespie, Jr. 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 & Nuclear Chief Operating Officer for Duke Energy Corporation ("Duke Energy").

Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT & NUCLEAR CHIEF OPERATING OFFICER?

A. As Senior Vice President & Nuclear Chief Operating Officer, I am responsible for providing executive oversight for the safe and reliable operation of Duke Energy's six nuclear plants including Duke Energy Progress, LLC's ("DEP" or "the Company") Brunswick Nuclear Plant ("Brunswick") located in Brunswick County, North Carolina, Harris Nuclear Plant ("Harris") located in Wake County, North Carolina, and Robinson Nuclear Plant ("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 Clemson University. I am a registered professional engineer in South Carolina, and held a senior operator license from the U.S. Nuclear Regulatory Commission ("NRC"). I began my career with Duke Energy Carolinas, LLC ("DEC", formerly known as Duke Power Company) in 1986 as an assistant engineer at Oconee Nuclear Station ("Oconee"). Since that time, I have held various roles of increasing responsibility in engineering and operations, including shift operations manager, and nuclear engineering manager in 2004 responsible for managing the nuclear and electrical engineering activities at Oconee. I was named operations manager at Catawba Nuclear Station in 2007, and in 2008 I became plant manager at Oconee, transitioning to Site Vice President in September 2010. I became Senior Vice President of Nuclear Operations responsible for Robinson and DEC's Oconee Nuclear Plant in March 2013, and assumed responsibility for the remaining nuclear facilities in September 2014. In September 2016, I transitioned into my current role as Nuclear Chief Operating Officer.

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

A. Yes. I submitted testimony in DEP's 2017 General Rate Case in Docket No. E-2, Sub 1142, DEC's 2016 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1104, and DEC's 2015 proceeding in Docket No. E-7, Sub 1072.

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

A. The purpose of my testimony is to describe and discuss the operational performance of Brunswick, Harris, and Robinson for the period of April 1, 2016 through March 31, 2017 ("test period"). I also discuss the nuclear capacity factor being proposed by DEP and used in this proceeding for determining the fuel factor to be reflected in rates during the billing period of December 1, 2017 through November 30, 2018 ("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 change based on fluctuations in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEP'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 3,539 megawatts ("MWs") of generating capacity, made up as follows:

Brunswick -	1,870 MWs
Harris -	928 MWs
Robinson -	741 MWs

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

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

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

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

A. No

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

A. The primary objective of DEP's nuclear generation department is to safely provide reliable and cost-effective electricity to DEP's Carolinas customers. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with detailed procedures. 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 effectively ready the plant 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 providing 46.3% of the total power generated by DEP during the 12 months ending March 2017 ("test period"), and achieved a system capacity factor of

93.65%. Leading into the fall 2016 refueling and maintenance outage, Harris completed a 511 day breaker-to-breaker run and established a new 9-month generation record. On March 17, 2017, Brunswick Unit 2 completed a 712 day breaker-to-breaker run setting a new performance record for the unit, station, and the Company. On a calendar year basis, the DEP nuclear fleet produced the second highest annual output during 2016, falling just below the record established in 2014.

The Company is also continually engaged in efforts to improve safety margins and operating efficiencies. In 2017, the Nuclear Energy Institute ("NEI") recognized the Company's efforts in three initiatives; Utilization of FLEX Equipment, Core Shroud Inspections, and Procurement Engineering Prioritization. The Utilization of FLEX Equipment initiative was developed by the Harris team, allowing the plant to use FLEX equipment enabling replacement of the Emergency Service Water ("ESW") pump while at full power. This initiative increased safety and reduced costs. Brunswick, in partnership with AREVA, was recognized for developing a new ultrasonic technique and remote tooling to facilitate required periodic shroud inspections. This new technique and tooling will provide approximately $1.8M in cost avoidance through 2020. Finally, our procurement engineering organization was recognized for the development of the Procurement Engineering Prioritization, Reporting, and Obsolescence ("PE PRO") application. The new application facilitates the prioritization and real-time tracking of procurement engineering requirements. The fleet-wide deployment of the PE PRO application improves safety and increases efficiency.

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

A. The Company's nuclear fleet has a history of solid performance. The most recently published North American Electric Reliability Council's ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") indicates an industry average capacity factor of 88.94% for comparable units representing the period 2011 through 2015. This is the standard considered by the Commission in establishing fuel factors in proceedings such as this. The Company's test period capacity factor of 93.65% and 2-year average[1] of 92.34% both exceed the NERC comparable average of 88.94%.

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, Institute of Nuclear Power Operations performance index, and total operating cost. Industry benchmarking efforts are a principal technique used by the Company to ensure best practices. These efforts further ensure overall prudence, safety, and reliability of DEP's nuclear units.

[1] This represents the simple average for the current test period and prior test period of 12 months ended March 2016 for the DEP nuclear fleet.

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

A. In general, refueling requirements, maintenance requirements, prudent maintenance practices, and NRC operating requirements impact the availability of DEP's nuclear system. Prior to a planned outage, DEP develops a detailed schedule for the outage and for major tasks to be performed including sub-schedules for particular activities.

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

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

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

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

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

A. Yes. The Nuclear industry recognizes that constant focus on raising standards and excellence in operations results in improved nuclear safety and reliability.

As such, 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 from the perspective of identifying areas in which it can utilize self-critical observation for improvement efforts. Given this focus on identifying opportunities for improvement, these critiques and cause analyses do not document the broader context of the outage extension or event, or account for the Company's attempt to achieve "best ever" outage time, and thus rarely acknowledge or reflect DEP's strengths and successes.

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

A. DEP completed one refueling and maintenance outage at Harris during the test period. Harris began a refueling and maintenance outage on October 8, 2016 and returned to service on November 11, 2016; a duration of 34.3 days. In addition to refueling and maintenance activities, modification activities included turbine supervisory instrumentation upgrades and the replacement of 24 motor control center buckets, 5 DC safety bus breakers, and 60 7.5KVA inverters. Emergency service cooling water throttle valves and service water valves were replaced and main feed pump, heater drain pump, and condensate pump and motor replacements or rebuilds were completed. Efficiency gains were achieved by the replacement of moisture separator reheaters. Scheduled reactor vessel head inspections identified indications on four penetrations requiring repair. While contingency plans were in place, these repairs were not accommodated in the original outage allocation window. The outage was extended 8.3 days beyond the original outage allocation, primarily driven by the reactor vessel head repairs. In total, DEP completed 8,219 activities within this outage.

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 92.6% capacity factor and believes that this capacity factor is reasonable 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 88.94% for comparable units as reported in the NERC Brochure representing the period of 2011 to 2015.

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

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET E-2, SUB 1146

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	)
___________________________________	)

T. PRESTON GILLESPIE, JR.
CONFIDENTIAL EXHIBIT 1

FILED UNDER SEAL

June 21, 2017

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1146

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, 2016 through March 31, 2017 test period ("test period"), and (3) describe changes forthcoming for the December 1, 2017 through November 30, 2018 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 smoothing out DEP's exposure to price volatility. Diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

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

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

DEP's portfolio of diversified contract pricing yielded an average unit cost of $36.68 per pound for uranium concentrates during the test period, representing a decrease of 4% 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 smoothing out DEP's exposure to price volatility. The average unit cost of DEP's purchases of enrichment services during the test period increased 6% to $141.35 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 – 12% and 5%, respectively, for the fuel batches recently loaded into DEP's reactors – of DEP's total direct fuel cost relative to uranium concentrates or enrichment, which are 41% and 42%, respectively.

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 production cutbacks are warranted in the near term due to 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 an increase in nuclear fuel costs on a cents per kilowatt hour ("kWh") basis through the next billing period. Because fuel is typically expensed over two to three operating cycles (roughly three to six years), DEP's nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period, as well as prior periods. The fuel residing in the reactors during the billing period will have been obtained under historical contracts negotiated in various market conditions. Each of these contracts contribute to a portion of the uranium, conversion, enrichment, and fabrication costs reflected in the total fuel expense.

The average fuel expense is expected to increase from 0.675 cents per kWh incurred in the test period, to approximately 0.714 cents per kWh in the billing period. This change reflects the discharge of fuel with a lower cost basis from the reactors and its replacement with fuel procured under new contracts negotiated in higher 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?

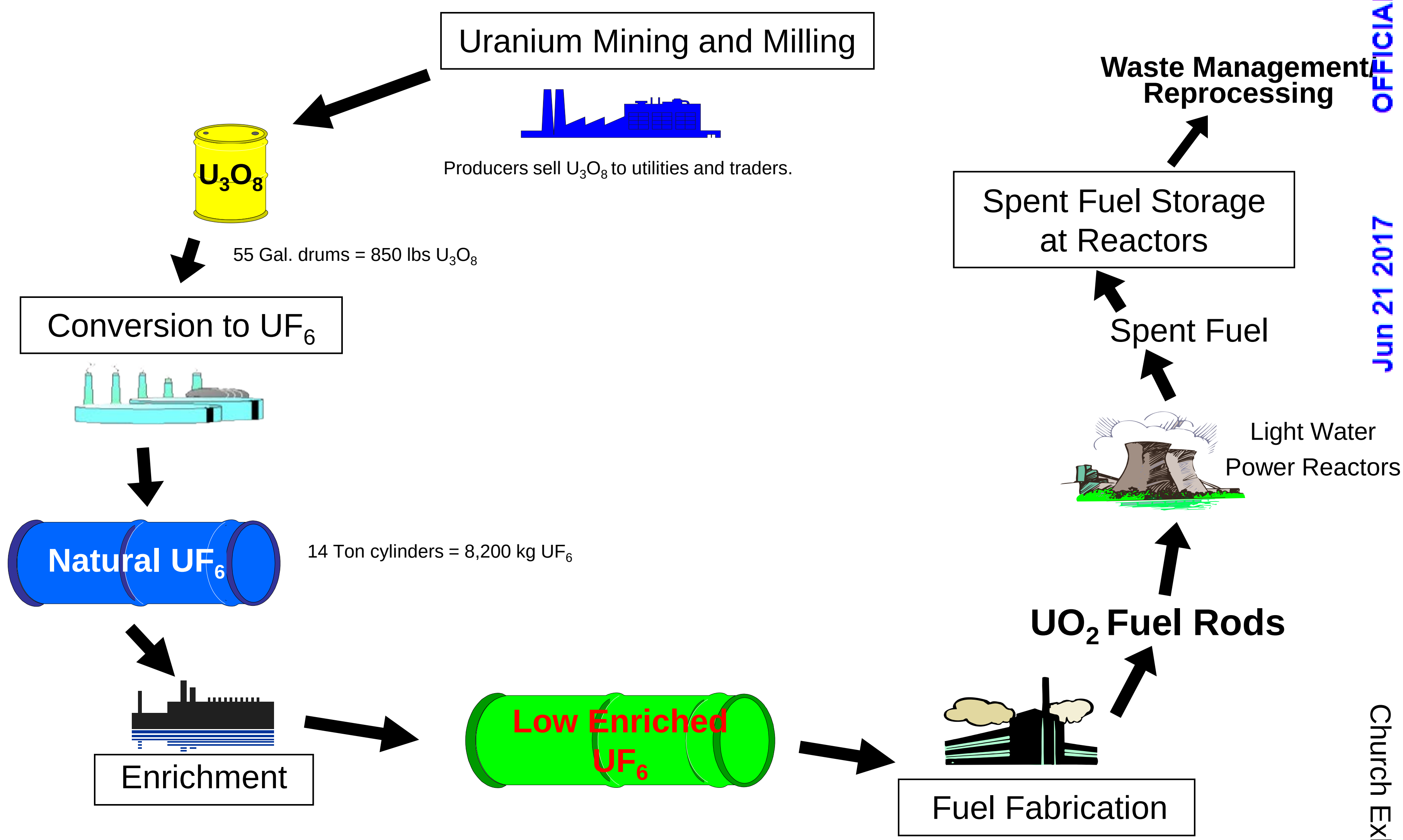
A. As I discussed earlier and as described in Church Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEP relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating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

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

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

A. Yes, it does.

The Nuclear Fuel Cycle



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 Duke Energy Progress has instructed delivery. Payments for such delivered volumes are made after Duke Energy Progress' receipt of such delivery facility confirmations.