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February 25, 2020

VIA ELECTRONIC FILING AND HAND DELIVERY

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

**RE: Duke Energy Carolinas, LLC's Fuel Charge Adjustment Proceeding
Docket No. E-7, Sub 1228**

Dear Ms. Campbell:

Enclosed for filing with the North Carolina Utilities Commission ("NCUC" or the "Commission") is the Application of Duke Energy Carolinas, LLC ("DEC") 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 and exhibits of Kimberly D. McGee, Brett Phipps, Regis Repko, Kevin Y. Houston, and Steven D. Capps containing the information required in NCUC Rule R8-55. I will deliver (15) paper copies of the filing to the Clerk's Office by close of business on February 26, 2020.

Certain information contained in the exhibits of Mr. Capps and Mr. Phipps is a trade secret, and confidential, proprietary, and commercially sensitive information. For this reason, it is being filed under seal pursuant to N.C. Gen. Stat. § 132-1.2. Parties to the docket may contact the Company regarding obtaining copies pursuant to an appropriate confidentiality agreement.

Please contact me if you have any questions.

Sincerely,

Jack E. Jirak

Enclosures
cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's Fuel Charge Adjustment Proceeding, in Docket No. E-7, Sub 1228, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 25th day of February, 2020.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

In the Matter of Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	**DUKE ENERGY CAROLINAS, LLC'S APPLICATION**

Duke Energy Carolinas, LLC ("DEC," "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 550 South Tryon Street, Charlotte, North Carolina, and its mailing address is:

Duke Energy Carolinas, LLC
P. O. Box 1006
Charlotte, North Carolina 28201-1006

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

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

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

4. In Docket No. E-7, Sub 1190, DEC's last fuel case, the Commission approved the following base fuel and fuel-related costs factors (excluding gross receipts tax and regulatory fee):

Residential -	1.9501 ¢ per kWh
Commercial -	2.0488 ¢ per kWh
Industrial -	2.1023 ¢ per kWh

5. In this Application, DEC proposes base fuel and fuel-related costs factors (excluding gross receipts tax and regulatory fee) of:

Residential -	1.5959¢ per kWh
Commercial -	1.7561¢ per kWh
Industrial -	1.6827¢ per kWh

The base fuel and fuel-related cost factors should be adjusted for the Experience Modification Factor ("EMF") by an increment/(decrement) (excluding gross receipts tax and regulatory fee) of:

Residential - 0.1574¢ per kWh
Commercial - 0.1510¢ per kWh
Industrial - 0.3067¢ per kWh

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

Residential - 0¢ per kWh
Commercial - 0¢ per kWh
Industrial - 0¢ per kWh

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

Residential - 1.7533¢ per kWh
Commercial - 1.9071¢ per kWh
Industrial - 1.9939¢ per kWh

The new fuel factors would have an effective date of September 1, 2020.

6. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Kevin Y. Houston, Kimberly McGee, Brett Phipps, Regis Repko and Steven D. Capps 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 weighted average nuclear capacity factor (91.60%) and projected period sales and the methodology used for fuel costs in DEC's last general rate case. These base fuel and fuel-related costs factors are:

	NERC Average	Last General Rate Case
Residential -	1.7932¢ per kWh	1.7523¢ per kWh
Commercial -	1.9358¢ per kWh	1.9024¢ per kWh
Industrial -	2.0159¢ per kWh	1.9920¢ per kWh

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

Residential -	1.7533¢ per kWh
Commercial -	1.9071¢ per kWh
Industrial -	1.9939¢ per kWh

Respectfully submitted this 25th day of February , 2020.

By: ____________________

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ATTORNEYS FOR DUKE ENERGY CAROLINAS, LLC

STATE OF NORTH CAROLINA)
) VERIFICATION
COUNTY OF MECKLENBURG)

Kimberly McGee, being first duly sworn, deposes and says:

That she is RATES MANAGER for DUKE ENERGY CAROLINAS, LLC, applicant in the above-titled action; 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.

Kimberly McGee

Kimberly McGee

Sworn to and subscribed before
me this the 20th day of February, 2020.

Aloma M Felder

Notary Public Aloma M. Felder

My Commission expires: July 21, 2020

ALOMA M. FELDER
NOTARY PUBLIC
CABARRUS COUNTY, N.C.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kimberly McGee. My business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am Rates Manager for Duke Energy Carolinas LLC ("DEC" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from the University of North Carolina at Charlotte with a Bachelor of Science degree in Accountancy. I am a certified public accountant licensed in the State of North Carolina. I began my career in 1989 with Deloitte and Touche, LLP as a staff auditor. In 1992, I began working with DEC (formerly known as Duke Power Company) as a staff accountant and have held a variety of positions in the finance organization. From 1997 until 2009, I worked for Wachovia Bank (now known as Wells Fargo) in a variety of finance and regulatory positions. I rejoined DEC in January 2009 as a Lead Accountant in Financial Reporting. I joined the Rates Department in 2011 as Manager, Rates and Regulatory Filings.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES MANAGER FOR DEC.

A. I am responsible for providing regulatory support for retail and wholesale rates, and providing guidance on DEC's fuel and fuel-related cost recovery application in North Carolina, and its fuel cost recovery application in South Carolina.

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

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC" or the "Commission") in DEP's general rate case proceeding supporting the base fuel factors in Docket No. E-2, Sub 1142 and provided testimony in DEC's general rate case proceeding supporting the base fuel factors in Docket No. E-7, Sub 1146. I also testified supporting cost recovery in the 2013 Demand Side Management and Energy Efficiency Rider in Docket No. E-7, Sub 1031. I submitted testimony in DEC's fuel and fuel-related cost recovery proceeding E-7, Subs 1190, 1163 and 1129 and DEP's fuel and fuel-related cost recovery proceedings in Docket No. E-2, Subs, 1045, 1069 and 1107.

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

A. Yes. DEC's 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 McGee Exhibits 1 through 6, along with supporting work papers. The test period used in supplying this information and data is the twelve months ended December 31, 2019 ("test period"), and the billing period is September 1, 2020 through August 31, 2021 ("billing period").

Q. WHAT IS THE SOURCE OF THE ACTUAL INFORMATION AND

DATA FOR THE TEST PERIOD?

A. Actual test period kilowatt hour ("kWh") generation, kWh sales, fuel-related revenues, and fuel-related expenses were taken from DEC's books and records. These books, records, and reports of DEC are subject to review by the appropriate regulatory agencies in the three jurisdictions that regulate DEC'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 DEC's financial statements are accurate.

Q. WERE MCGEE 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 94.39% proposed nuclear capacity factor and projected megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 94.39% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 91.60% 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 general service/lighting customers.

Page 4: Calculation of the EMF for industrial customers.

Exhibit 4: MWh 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: December 2019 Monthly Fuel Reports.

1) December 2019 Monthly Fuel Report required by NCUC Rule R8-52.

2) December 2019 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

Q. PLEASE EXPLAIN MCGEE EXHIBIT 1.

A. McGee 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 factor calculations as required under Rule R8-55, and the proposed fuel and fuel-related cost factors.

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

A. DEC proposes fuel and fuel-related costs factors for residential, general service/lighting, and industrial customers of 1.7533¢, 1.9071¢, and 1.9939¢ per kWh, respectively, to be reflected in rates during the billing period. The factors DEC proposes in this proceeding incorporate a 94.39% nuclear capacity factor as testified to by Company witness Capps, projected fossil fuel costs as testified to by Company witness Phipps, projected nuclear fuel costs as testified to by Company witness Houston, and projected reagents costs as testified to by Company witness Repko. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on McGee Exhibit 1, are as follows:

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Total adjusted Fuel and Fuel Related Costs	1.5959	1.7561	1.6872	1.6827
EMF Increment (Decrement)	0.1574	0.1510	0.3067	0.1866
Net Fuel and Fuel Related Costs Factors	1.7533	1.9071	1.9939	1.8693

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

A. The proposed fuel and fuel-related costs factors will result in a 1.90% decrease on customers' bills. The table below shows both the proposed and existing fuel and fuel-related costs factors.

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Proposed Total Fuel Factor	1.7533	1.9071	1.9939	1.8693
Existing Total Fuel Factor	1.9501	2.0488	2.1023	2.0247

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

A. The decrease in the proposed net fuel and fuel-related costs factors for all customer classes is primarily driven by a decrease in commodity prices and corresponding change in generation mix. This decline in costs is partially offset by the increase of $31 million in under-collection for the current test period versus the under-collection included in current rates.

Company witness Houston explains that the billing period price of 0.6040¢ per kWh for nuclear fuel is higher than experienced during the test period but lower than the prices reflected in current rates. As discussed by Company witness Phipps, the proposed fuel and fuel-related costs factors include an average delivered cost for coal received for the billing period of $73.90 per ton, which is 10% lower than the average delivered cost of coal received per ton during the test period and lower than prices reflected in current rates. In addition, Company witness Phipps notes a decrease in natural gas prices as evidenced by the Henry Hub[1] forward price of $2.44 per Million British Thermal Units ("MMBtu") used in the proposed fuel rates, compared to $2.63 per MMBtu in the test period.

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

A. For this filing, DEC used an hourly dispatch model in order to generate its fuel

[1] "Henry Hub" pipeline is the location used for physical settlement of the New York Mercantile Exchange futures contracts.

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 DEC's and DEP's generation resources via joint dispatch, which optimizes the generation fleets of DEC and DEP for the benefit of customers.

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

A. Exhibit 2 is divided into three schedules. Schedule 1 sets forth system fuel costs used in the determination of the prospective fuel and fuel-related costs. The calculation uses the nuclear capacity factor of 94.39%, and provides the forecasted MWh sales for the billing period on which system generation and costs are based.

Schedule 2 also uses the proposed capacity factor of 94.39% 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 DEC'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 91.60%. This capacity factor is based on the 2014 through 2018 data reported in the NERC Generating Unit Statistical Brochure for pressurized water reactors rated at and above 800 MWs. Projected billing period kWh generation was also used for Schedule 3 per 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, which is the same allocation methodology used in the latest general rate case in Docket E-7, Sub 1146.

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 DEC's proposed fuel and fuel-related costs factors for the residential, general service/lighting and industrial 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 MCGEE EXHIBIT 2, SCHEDULES 2 AND 3.

A. The methodology used by DEC in its most recent general rate case for determining generation mix is based upon generation dispatch modeling as used on McGee Exhibit 2, Schedule 1. For purposes of this filing, as a proxy for generation dispatch modeling, McGee 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, DEC 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, DEC increased the level of coal generation to account for the decrease in nuclear generation. The decrease in nuclear generation results from assuming an 91.60% NERC nuclear capacity factor compared to the proposed 94.39% nuclear capacity factor.

Q. MCGEE 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. McGee Exhibit 3, Pages 1 through 4, demonstrates that for the test period, DEC experienced an under-recovery for the residential, general service/lighting and industrial customer classes of $35.3 million, $35.8 million, and $38.3 million, respectively.

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: (1) capacity-related purchased power costs were allocated among customer classes based on production plant allocators from DEC's cost of service study and (2) all other fuel and fuel-related costs were allocated among customer classes based on fixed allocation percentages established in DEC's previous fuel and fuel-related cost recovery proceeding based on the uniform percentage average bill adjustment method.

Q. PLEASE EXPLAIN MCGEE EXHIBIT 4.

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), McGee 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 and adjusted for projected customer growth. Both of these adjustments were determined using the methods approved for use in DEC's last general rate case (Docket No. E-7, Sub 1146) and used in its last fuel proceeding. McGee Exhibit 4 also sets forth actual test period fuel-related revenue and fuel expense on a total DEC basis and for North Carolina retail. Finally, McGee Exhibit 4 shows the test period peak demand for the system and for North Carolina retail customer classes.

Q. PLEASE EXPLAIN MCGEE EXHIBIT 5.

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

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

A. Yes. As shown on McGee Exhibit 6, DEC's test year actual fuel and fuel-related costs were 1.9908¢ per kWh. Key factors in DEC's ability to maintain lower fuel and fuel-related rates for the benefit of customers include (1) its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; (2) lower natural gas prices; (3) the high capacity factors of its nuclear fleet; and (4) fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of DEC's and DEP's respective skills in procuring, transporting, managing, and blending fuels, procuring reagents and the increased and broader purchasing ability of Duke Energy Corporation after its merger with Progress Energy, Inc., as well as the joint dispatch of DEC's and DEP's generation resources. Company witness Capps discusses the performance of DEC's nuclear generation fleet, and Company witness Repko discusses the performance of the fossil and hydro fleet, as well as the use of chemicals for reducing emissions. Company witness Phipps discusses fossil fuel procurement strategies, and Company witness Houston discusses DEC's nuclear fuel costs and procurement strategies.

Q. IN DEVELOPING THE PROPOSED FUEL AND FUEL-RELATED COSTS 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 the same as used in DEC's latest general rate case, Docket No. E-7, Sub 1146 and are as follows:

(a) 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.

(b) Subdivision (4) costs and non-capacity related 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 AND FUEL-RELATED 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. DEC 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 2019 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1190.

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

A. McGee Exhibit 2, Page 3 of Schedule 1, shows DEC's proposed fuel and fuel-related cost factors for the residential, general service/lighting and industrial classes, exclusive of regulatory fee. The uniform bill percentage change of (1.90%) was calculated by dividing the fuel and fuel-related cost decrease of $90,846,978 for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $4,774,276,270. The cost decrease of $90,846,978 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 represents the rate necessary to recover projected period fuel costs for the billing period (as computed on McGee Exhibit 2, Schedule 1), the proposed composite EMF increment rate (as computed on McGee Exhibit 3, page 1). This results in a uniform bill percentage change of (1.90)%. McGee 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 COSTS FACTORS FOR EACH CUSTOMER CLASS DERIVED FROM THE UNIFORM PERCENT ADJUSTMENT COMPUTED ON MCGEE EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. McGee Exhibit 2, Page 3 of Schedules 1, 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, with the breakdown shown on McGee Exhibit 2, Page 2 of Schedules 2 and 3. The equal percent increase or decrease for each customer class is applied to current annual revenues by customer class to determine a dollar amount of increase or decrease for each customer class. The dollar increase or decrease is divided by the projected billing period sales for each class to derive a cents per kWh increase or decrease. The current total fuel and fuel-related cost factors for each class are increased or decreased by the proposed cents per kWh increases or decreases to get the proposed total fuel and fuel-related cost factors. The proposed total factors are then separated into the prospective and EMF components by subtracting the EMF components for each customer class (as computed on McGee Exhibit 3, Page 2, 3, and 4) to derive the prospective component for each customer class. This breakdown is shown on McGee Exhibit 2, Page 2 of Schedules 1, 2, and 3.

Q. HAS DEC'S ANNUAL INCREASE IN THE AGGREGATE AMOUNT OF THE COSTS IDENTIFIED IN SUBDIVISIONS (4), (5), AND (6) OF N.C. GEN. STAT. § 62-133.2(a1) EXCEEDED 2.5% OF ITS NORTH CAROLINA RETAIL GROSS REVENUES FOR THE TEST PERIOD?

A. No. N.C. Gen. Stat. § 62-133.2(a2) limits the amount of annual increase in certain purchased power costs identified in § 62-133.2(a1) that DEC can recover to 2.5% of its North Carolina retail gross revenues for the preceding calendar year. The amount recoverable in DEC's proposed rates for purchased power under the relevant sections of N.C. Gen. Stat. § 62-133.2(a1) does not increase by more than 2.5% of DEC's gross revenues for its North Carolina retail jurisdiction for the test period.

Q. HAS DEC 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 CAROLINAS **McGee Exhibit 1**

North Carolina Annual Fuel and Fuel Related Expense
Summary Comparison of Fuel and Fuel Related Cost Factors
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Description	Reference	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
	Current Fuel and Fuel Related Cost Factors (Approved Fuel Rider Docket No. E-7, Sub 1190)					
1	Approved Fuel and Fuel Related Costs Factors	Input	1.8126	1.9561	1.8934	1.8901
2	EMF Increment	Input	0.1375	0.0927	0.2089	0.1346
3	EMF Interest Decrement cents/kWh	Input	0.0000	0.0000	0.0000	0.0000
4	Approved Net Fuel and Fuel Related Costs Factors	Sum	**1.9501**	**2.0488**	**2.1023**	**2.0247**
	Fuel and Fuel Related Cost Factors Required by Rule R8-55					
5	Proposed Nuclear Capacity Factor of 94.39% and Normalized Test Period Sales	Exh 2 Sch 2 pg 2	**1.7523**	**1.9024**	**1.9920**	**1.8663**
6	NERC 5 Year Average Nuclear Capacity Factor of 91.60% and Projected Period Sales	Exh 2 Sch 3 pg 2	**1.7932**	**1.9358**	**2.0159**	**1.9008**
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 94.39%					
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	1.5606	1.7286	1.6648	1.6533
8	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.0353	0.0275	0.0224	0.0294
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	1.5959	1.7561	1.6872	1.6827
10	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.1574	0.1510	0.3067	0.1866
11	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.0000	0.0000	0.0000	0.0000
12	Net Fuel and Fuel Related Costs Factors cents/kWh	Sum	**1.7533**	**1.9071**	**1.9939**	**1.8693**

Note: Fuel factors exclude regulatory fee

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.39%
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	59,363,957	0.6041	358,597,316
2	Coal	Workpaper 3 & 4	14,450,043	2.7303	394,529,148
3	Gas CT and CC	Workpaper 3 & 4	25,505,409	2.2867	583,236,234
4	Reagents and Byproducts	Workpaper 9			22,532,174
5	Total Fossil	Sum	39,955,452		1,000,297,556
6	Hydro	Workpaper 3	4,305,885		
7	Net Pumped Storage	Workpaper 3	(3,219,894)		
8	Total Hydro	Sum	1,085,991		-
9	Solar Distributed Generation	Workpaper 3	385,094		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	100,790,494		1,358,894,872
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(16,315,588)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,848,200)		(89,710,135)
13	Fuel expense recovered through reimbursement	Workpaper 4			(20,370,677)
14	Net Generation	Sum Lines 10-13	85,066,294		1,232,498,472
15	Purchased Power	Workpaper 3 & 4	8,286,802	3.1208	258,610,852
16	JDA Savings Shared	Workpaper 5			14,281,717
17	Total Purchased Power		8,286,802		272,892,569
18	Total Generation and Purchased Power	Line 14 + Line 17	93,353,096	1.6126	1,505,391,041
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,024,819)	2.0734	(21,248,787)
20	Line losses and Company use	Line 22-Line 18-Line 19	(3,945,038)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,484,142,254
22	Projected System MWh Sales for Fuel Factor	Workpaper 7	88,383,239		88,383,239
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.6792

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.39%
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7	22,067,951	23,951,115	12,441,023	58,460,089
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,122,631
3	QF Purchased Power - Capacity	Workpaper 4				12,285,396
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 25,408,027
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input				67.55%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 17,162,430
7	Production Plant Allocation Factors	Input	45.44%	38.35%	16.21%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 7,799,064	$ 6,581,827	$ 2,781,540	$ 17,162,430
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0353	0.0275	0.0224	0.0294
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	1.5606	1.7286	1.6648	1.6533
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0353	0.0275	0.0224	0.0294
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.5959	1.7561	1.6872	1.6827
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.1574	0.1510	0.3067	0.1866
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	1.7533	1.9071	1.9939	1.8693

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.39%
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	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)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1190	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	D	E	F	G
		Workpaper 7	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	McGee Exhibit 1	E + F = G
1	Residential	22,067,951	$ 2,282,179,536	$ (43,426,292)	-1.90%	(0.1968)	1.9501	1.7533
2	General Service/Lighting	23,951,115	1,783,527,535	(33,937,727)	-1.90%	(0.1417)	2.0488	1.9071
3	Industrial	12,441,023	708,569,199	(13,482,959)	-1.90%	(0.1084)	2.1023	1.9939
4	NC Retail	58,460,089	$ 4,774,276,270	$ (90,846,978)	-1.90%			

Line #	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
5	Total Fuel Costs for Allocation	Workpaper 7	$ 1,489,416,245
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	25,408,027
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,464,008,218
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7	88,545,366
9	NC Retail Projected Billing Period MWh Sales	Line 4	58,460,089
10	Allocation %	Line 9 / Line 8	66.02%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 966,538,226
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 1, Page 2	17,162,430
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 983,700,656
14	NC Retail Projected Billing Period MWh Sales	Line 4	58,460,089
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.6827
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.1866
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	1.8693
	Total Current Composite Fuel Rate - Docket E-7 Sub 1190:		
19	Current composite Fuel Rate cents/kWh	McGee Exhibit 1	1.8901
20	Current composite EMF Rate cents/kWh	McGee Exhibit 1	0.1346
21	Current composite EMF Interest Rate cents/kWh	McGee Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	2.0247
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	(0.1554)
24	NC Retail Projected Billing Period MWh Sales	Line 4	58,460,089
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ (90,846,978)

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.39% and Normalized Test Period Sales
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	59,363,957	0.6041	358,597,316
2	Coal	Calculated	14,197,575	2.7303	387,636,026
3	Gas CT and CC	Workpaper 3 & 4	25,505,409	2.2867	583,236,234
4	Reagents and Byproducts	Workpaper 9	-		22,532,174
5	Total Fossil	Sum	39,702,984		993,404,434
6	Hydro	Workpaper 3	4,305,885		
7	Net Pumped Storage	Workpaper 3	(3,219,894)		
8	Total Hydro	Sum	1,085,991		
9	Solar Distributed Generation		385,094		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	100,538,026		1,352,001,750
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(16,315,588)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,848,200)		(89,710,135)
13	Fuel expense recovered through reimbursement	Workpaper 4			(20,370,677)
14	Net Generation	Sum	84,813,826		1,225,605,350
15	Purchased Power	Workpaper 3 & 4	8,286,802		258,610,852
16	JDA Savings Shared	Workpaper 5	-		14,281,717
17	Total Purchased Power	Sum	8,286,802		272,892,569
18	Total Generation and Purchased Power	Line 14 + Line 17	93,100,628		1,498,497,919
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,024,819)		(21,248,787)
20	Line losses and Company use	Line 22 - Line 19 - Line 18	(3,945,038)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,477,249,132
22	Normalized Test Period MWh Sales	Exhibit 4	88,130,771		88,130,771
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.6762

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.39% and Normalized Test Period Sales
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Normalized Test Period MWh Sales	Exhibit 4	22,444,481	23,688,550	12,489,508	58,622,539
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,122,631
3	QF Purchased Power - Capacity	Workpaper 4				12,285,396
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 25,408,027
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input				67.55%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 17,162,430
7	Production Plant Allocation Factors	Input	45.44%	38.35%	16.21%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 7,799,064	$ 6,581,827	$ 2,781,540	$ 17,162,430
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0347	0.0278	0.0223	0.0293
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	1.5602	1.7236	1.6630	1.6504
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0347	0.0278	0.0223	0.0293
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.5949	1.7514	1.6853	1.6797
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.1574	0.1510	0.3067	0.1866
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	1.7523	1.9024	1.9920	1.8663

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.39% and Normalized Test Period Sales
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Rate Class	Normalized Test Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/(Decrease) as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1190	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	D	E	F	G
		Exhibit 4	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	McGee Exhibit 1	E + F = G
1	Residential	22,444,481	$ 2,282,179,536	$ (44,387,641)	-1.94%	(0.1978)	1.9501	1.7523
2	General Service/Lighting	23,688,550	$ 1,783,527,535	(34,689,024)	-1.94%	(0.1464)	2.0488	1.9024
3	Industrial	12,489,508	$ 708,569,199	(13,781,438)	-1.94%	(0.1103)	2.1023	1.9920
4	NC Retail	58,622,539	$ 4,774,276,270	$ (92,858,103)				

Line #			
	Total Proposed Composite Fuel Rate:		
5	Total Fuel Costs for Allocation	Workpaper 7a	$ 1,482,523,124
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	25,408,027
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,457,115,097
8	Normalized Test Period System MWh Sales for Fuel Factor	Workpaper 7a	88,292,898
9	NC Retail Normalized Test Period MWh Sales	Exhibit 4	58,622,539
10	Allocation %	Line 9 / Line 8	66.40%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 967,524,424
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 2, Page 2	17,162,430
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 984,686,854
14	NC Retail Normalized Test Period MWh Sales	Line 9	58,622,539
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.6797
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.1866
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	1.8663
	Total Current Composite Fuel Rate - Docket E-7 Sub 1190:		
19	Current composite Fuel Rate cents/kWh	McGee Exhibit 1	1.8901
20	Current composite EMF Rate cents/kWh	McGee Exhibit 1	0.1346
21	Current composite EMF Interest Rate cents/kWh	McGee Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	2.0247
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	(0.1584)
24	NC Retail Normalized Test Period MWh Sales	Exhibit 4	58,622,539
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ (92,858,102)

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor of 91.60% and Projected Period Sales
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 2	57,614,320	0.6041	348,028,357
2	Coal	Calculated	15,762,058	2.7303	430,351,081
3	Gas CT and CC	Workpaper 3 & 4	25,505,409	2.2867	583,236,234
4	Reagents and Byproducts	Workpaper 9	-		22,532,174
5	Total Fossil	Sum	41,267,467		1,036,119,489
6	Hydro	Workpaper 3	4,305,885		
7	Net Pumped Storage	Workpaper 3	(3,219,894)		
8	Total Hydro	Sum	1,085,991		
9	Solar Distributed Generation	Workpaper 3	385,094		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	100,352,872		1,384,147,846
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(16,315,588)
12	Less Catawba Joint Owners	Calculated	(14,410,578)		(87,066,102)
13	Fuel expense recovered through reimbursement	Workpaper 4			(20,370,677)
14	Net Generation	Sum	85,066,294		1,260,395,479
15	Purchased Power	Workpaper 3 & 4	8,286,802		258,610,852
16	JDA Savings Shared	Workpaper 5	-		14,281,717
17	Total Purchased Power	Sum	8,286,802		272,892,569
18	Total Generation and Purchased Power	Line 14 + Line 17	93,353,096		1,533,288,048
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,024,819)		(21,248,787)
20	Line losses and Company use	Line 22 - Line 19 - Line 18	(3,945,038)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,512,039,261
22	Projected System MWh Sales for Fuel Factor	Workpaper 7b	88,383,239		88,383,239
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.7108

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
NERC 5 Year Average Nuclear Capacity Factor of 91.60% and Projected Period Sales
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7b	22,067,951	23,951,115	12,441,023	58,460,089
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,122,631
3	QF Purchased Power - Capacity	Workpaper 4				12,285,396
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 25,408,027
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input				67.55%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 17,162,430
7	Production Plant Allocation Factors	Input	45.44%	38.35%	16.21%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 7,799,064	$ 6,581,827	$ 2,781,540	$ 17,162,430
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0353	0.0275	0.0224	0.0294
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	1.6005	1.7573	1.6868	1.6848
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0353	0.0275	0.0224	0.0294
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.6358	1.7848	1.7092	1.7142
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.1574	0.1510	0.3067	0.1866
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	1.7932	1.9358	2.0159	1.9008

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
NERC 5 Year Average Nuclear Capacity Factor of 91.60% and Projected Period Sales
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	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)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1190	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	C / B = D	E	F	G
		Workpaper 7b	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	McGee Exhibit 1	E + F = G
1	Residential	22,067,951	$ 2,282,179,536	$ (34,623,665)	-1.52%	(0.1569)	1.9501	1.7932
2	General Service/Lighting	23,951,115	$ 1,783,527,535	$ (27,058,458)	-1.52%	(0.1130)	2.0488	1.9358
3	Industrial	12,441,023	$ 708,569,199	$ (10,749,927)	-1.52%	(0.0864)	2.1023	2.0159
4	NC Retail	58,460,089	$ 4,774,276,270	$ (72,432,050)				

Total Proposed Composite Fuel Rate:

5	Total Fuel Costs for Allocation	Workpaper 7b	$ 1,517,313,259
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	25,408,027
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,491,905,232
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7b	88,545,366
9	NC Retail Projected Billing Period MWh Sales	Line 4	58,460,089
10	Allocation %	Line 9 / Line 8	66.02%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 984,955,834
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 3, Page 2	17,162,430
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,002,118,264
14	NC Retail Projected Billing Period MWh Sales	Line 4	58,460,089
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.7142
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.1866
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	1.9008

Total Current Composite Fuel Rate - Docket E-7 Sub 1190:

19	Current composite Fuel Rate cents/kWh	McGee Exhibit 1	1.8901
20	Current composite EMF Rate cents/kWh	McGee Exhibit 1	0.1346
21	Current composite EMF Interest Rate cents/kWh	McGee Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	2.0247
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	(0.1239)
24	NC Retail Projected Billing Period MWh Sales	Line 4	58,460,089
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ (72,432,050)

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line No.	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2019 (1)			5,021,050	$	14,748,999
2	February			5,026,972	$	26,351,993
3	March(1)			4,366,364	$	6,488,079
4	April			4,263,830	$	846,148
5	May(1)			4,421,390	$	13,794,537
6	June			5,029,189	$	4,512,864
7	July			5,524,189	$	25,226,650
8	August			5,710,821	$	15,596,501
9	September			5,512,227	$	9,336,491
10	October(1)			4,692,562	$	(6,369,305)
11	November			4,299,809	$	6,118,779
12	December(1)			4,774,120	$	(7,262,312)
13	**Total Test Period**			**58,642,521**	**$**	**109,389,423**
14	**Total (Over)/ Under Recovery**				**$**	**109,389,423**
15	NC Retail Normalized Test Period MWh Sales			Exhibit 4		58,622,539
16	**Experience Modification Increment (Decrement) cents/kWh**					**0.1866**

[(1)] Prior period corrections not included in rate incurred but are included in over/(under) recovery total
Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWH Sales (c)	Reported (Over)/ Under Recovery (d)
1	January 2019 (1)	1.6843	1.7003	2,194,231	$ (326,600)
2	February	1.9667	1.7003	2,094,914	$ 5,580,727
3	March(1)	1.7655	1.7062	1,704,915	$ 946,440
4	April	1.9025	1.7062	1,446,157	$ 2,839,260
5	May(1)	2.3061	1.7062	1,438,256	$ 8,673,370
6	June	1.8414	1.7062	1,831,778	$ 2,477,447
7	July	2.0729	1.7062	2,144,971	$ 7,865,439
8	August	1.9124	1.7062	2,209,124	$ 4,555,238
9	September	1.9306	1.7648	2,048,666	$ 3,397,342
10	October(1)	1.7998	1.8179	1,627,070	$ (176,470)
11	November	2.1806	1.8185	1,422,163	$ 5,149,854
12	December(1)	1.5029	1.8127	1,929,578	$ (5,657,382)
13	**Total Test Period**			**22,091,823**	**$ 35,324,665**
14	Test Period Wtd Avg. ¢/kWh	1.8931	1.7352		
15	**Total (Over)/ Under Recovery**				**$ 35,324,665**
16	NC Retail Normalized Test Period MWh Sales			Exhibit 4	22,444,481
17	**Experience Modification Increment (Decrement) cents/kWh**				**0.1574**

Notes:
(1) Prior period corrections not included in rate incurred but are included in over/(under) recovery total

Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - GS/Lighting
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2019 (1)	2.2307	1.8314	1,936,499	$	7,761,641
2	February	2.5196	1.8314	1,911,117	$	13,151,612
3	March(1)	2.0159	1.8373	1,744,567	$	3,110,115
4	April	1.7881	1.8373	1,796,520	$	(884,254)
5	May(1)	1.9920	1.8373	1,944,912	$	3,019,902
6	June	1.8353	1.8373	2,140,511	$	(43,029)
7	July	2.2590	1.8373	2,277,488	$	9,604,973
8	August	2.0663	1.8373	2,362,000	$	5,409,863
9	September	1.9981	1.9024	2,322,021	$	2,224,259
10	October(1)	1.6777	1.9614	2,064,595	$	(5,747,964)
11	November	1.9803	1.9620	1,867,139	$	340,996
12	December(1)	1.8270	1.9562	1,892,532	$	(2,189,448)
13	**Total Test Period**			**24,259,901**	**$**	**35,758,666**
14	Test Period Wtd Avg. ¢/kWh	2.0178	1.8720			
15	**Total (Over)/ Under Recovery**				**$**	**35,758,666**
16	NC Retail Normalized Test Period MWh Sales			Exhibit 4		23,688,550
17	**Experience Modification Increment (Decrement) cents/kWh**					**0.1510**

Notes:
(1) Prior period corrections not included in rate incurred but are included in over/(under) recovery total
Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Industrial
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2019 (1)	2.6216	1.8020	890,321	$	7,313,957
2	February	2.5483	1.8020	1,020,942	$	7,619,655
3	March(1)	2.0724	1.8079	916,881	$	2,431,522
4	April	1.6993	1.8079	1,021,153	$	(1,108,857)
5	May(1)	2.0148	1.8079	1,038,221	$	2,101,265
6	June	2.0046	1.8079	1,056,900	$	2,078,447
7	July	2.5119	1.8079	1,101,729	$	7,756,238
8	August	2.3020	1.8079	1,139,697	$	5,631,400
9	September	2.1810	1.8556	1,141,540	$	3,714,890
10	October(1)	1.8500	1.8988	1,000,897	$	(444,872)
11	November	1.9614	1.8993	1,010,506	$	627,928
12	December(1)	1.9470	1.8935	952,010	$	584,518
13	**Total Test Period**			**12,290,797**	**$**	**38,306,091**
14	Test Period Wtd Avg. ¢/kWh	2.1439	1.8330			
15	**Total (Over)/ Under Recovery**				**$**	**38,306,091**
16	NC Retail Normalized Test Period MWh Sales			Exhibit 4		12,489,508
17	**Experience Modification Increment (Decrement) cents/KWh**					**0.3067**

Notes:
(1) Prior period corrections not included in rate incurred but are included in over/(under) recovery total
Rounding differences may occur

McGee Exhibit 4

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Sales, Fuel Revenue, Fuel Expense and System Peak
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Line #	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina General Service/Lighting	North Carolina Industrial
1	Test Period MWh Sales (excluding inter system sales)	Exhibit 6 Schedule 1 (Line 4) and Workpaper 11 (NC retail)	87,911,333	58,642,521	22,091,823	24,259,901	12,290,797
2	Customer Growth MWh Adjustment	Workpaper 13 Pg 1	455,048	296,714	185,000	48,348	63,366
3	Weather MWh Adjustment	Workpaper 12	(235,610)	(316,696)	167,658	(619,699)	135,345
4	Total Normalized MWh Sales	Sum	88,130,771	58,622,539	22,444,481	23,688,550	12,489,508
5	Test Period Fuel and Fuel Related Revenue *		$ 1,669,292,496	$ 1,062,783,555			
6	Test Period Fuel and Fuel Related Expense *		$ 1,749,171,043	$ 1,172,172,978			
7	Test Period Unadjusted (Over)/Under Recovery		$ 79,878,546	$ 109,389,423			

Line #	Description	Summer Coincidental Peak (CP) kW
8	Total System Peak	17,626,362
9	NC Retail Peak	11,906,127
10	NC Residential Peak	5,410,460
11	NC General Service/Lighting Peak	4,566,024
12	NC Industrial Peak	1,929,643

* 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 CAROLINAS **McGee Exhibit 5**
North Carolina Annual Fuel and Fuel Related Expense
Nuclear Capacity Ratings
Test Period Ended December 31, 2019
Billing Period September 2020 - August 2021
Docket E-7, Sub 1228

Unit	Rate Case Docket E-7, Sub 1146	Fuel Docket E-7, Sub 1190	Proposed Capacity Rating MW
Oconee Unit 1	847	847.0	847.0
Oconee Unit 2	848	848.0	848.0
Oconee Unit 3	859	859.0	859.0
McGuire Unit 1	1,158	1158.0	1158.0
McGuire Unit 2	1,158	1157.6	1157.6
Catawba Unit 1	1,160	1160.1	1160.1
Catawba Unit 2	1,150	1150.1	1150.1
Total Company	7,180	7,179.8	7,179.8

McGee Exhibit 6

DECEMBER 2019 MONTHLY FUEL FILING

DUKE ENERGY CAROLINAS
SUMMARY OF MONTHLY FUEL REPORT

Docket No. E-7, Sub 1198

Line No.		December 2019	12 Months Ended December 2019
1	Fuel and fuel-related costs	$ 122,817,184	$ 1,750,175,434
	MWH sales:		
2	Total system sales	7,221,215	89,956,771
3	Less intersystem sales	70,226	2,045,438
4	Total sales less intersystem sales	7,150,989	87,911,333
5	Total fuel and fuel-related costs (¢/KWH) (line 1/line 4)	1.7175	1.9908
6	Current fuel and fuel-related cost component (¢/KWH) (per Schedule 4, Line 7a Total)	1.8856	
	Generation Mix (MWH):		
	Fossil (by primary fuel type):		
7	Coal	1,208,156	20,916,177
8	Fuel Oil	7,779	97,907
9	Natural Gas - Combined Cycle	1,310,358	14,049,112
10	Natural Gas - Combined Heat and Power	(243)	(243)
11	Natural Gas - Combustion Turbine	56,622	1,062,059
12	Natural Gas - Steam	25,471	1,157,313
13	Biogas	2,160	17,335
14	Total fossil	2,610,303	37,299,660
15	Nuclear 100%	5,203,803	61,066,543
16	Hydro - Conventional	219,651	2,427,405
17	Hydro - Pumped storage	(48,643)	(713,520)
18	Total hydro	171,008	1,713,885
19	Solar Distributed Generation	8,911	142,127
20	Total MWH generation	7,994,025	100,222,215
21	Less joint owners' portion - Nuclear	1,409,284	15,822,621
22	Less joint owners' portion - Combined Cycle	297,823	893,946
23	Adjusted total MWH generation	6,286,918	83,505,648

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

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS

Docket No. E-7, Sub 1198

Fuel and fuel-related costs:	December 2019	12 Months Ended December 2019	
0501110 coal consumed - steam	$ 35,851,930	$ 688,831,904	
0501310 fuel oil consumed - steam	262,693	7,285,496	
0501330 fuel oil light-off - steam	740,317	6,451,433	
Total Steam Generation - Account 501	36,854,940	702,568,833	
Nuclear Generation - Account 518			
0518100 burnup of owned fuel	22,398,036	270,484,487	
Other Generation - Account 547			
0547100, 0547124 - natural gas consumed - Combustion Turbine	2,310,732	40,328,338	
0547100 natural gas consumed - Steam	1,596,367	42,380,517	
0547101 natural gas consumed - Combined Cycle	30,560,920	322,366,652	
0547101 natural gas consumed - Combined Heat and Power	54,658	54,658	
0547106 biogas consumed - Combined Cycle	116,664	936,054	
0547200 fuel oil consumed - Combustion Turbine	255,506	949,755	
Total Other Generation - Account 547	34,894,847	407,015,974	
Reagents			
Catalyst Depreciation Expense			**A**
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	1,165,420	24,629,578	
Total Reagents	1,165,420	24,629,578	
By-products			
Net proceeds from sale of by-products	1,314,235	8,920,508	
Total By-products	1,314,235	8,920,508	
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	96,627,478	1,413,619,380	
Purchased Power and Net Interchange - Account 555			
Capacity component of purchased power (economic)	213,366	10,668,301	
Capacity component of purchased power (renewables)	594,090	15,300,779	
Capacity component of purchased power (PURPA)	187,603	6,969,349	
Fuel and fuel-related component of purchased power	27,443,813	365,056,791	
Total Purchased Power and Net Interchange - Account 555	28,438,872	397,995,220	
Less:			
Fuel and fuel-related costs recovered through intersystem sales	2,169,260	60,148,973	
Fuel in loss compensation	79,276	1,279,432	
Solar Integration Charge	628	10,761	
Total Fuel Credits - Accounts 447 /456	2,249,164	61,439,166	
Total Fuel and Fuel-related Costs	$ 122,817,184	$ 1,750,175,434	

Notes: Detail amounts may not add to totals shown due to rounding.
Report reflects net ownership costs of jointly owned facilities.

A Reflects removal of catalyst depreciation expense from fuel costs. Associated prior period adjustment to over/under collection included on Schedule 4.

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

December 2019

Exhibit 6
Schedule 3 - Purchases
Page 1 of 4

Purchased Power	**Total**	**Capacity**	**Non-capacity**			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Cherokee County Cogeneration Partners	$ 1,679,149	$ 213,366	44,941	$ 1,262,453	$ 203,330	
DE Progress - Native Load Transfer	12,821,002	-	679,100	11,796,943	1,024,484	$ (425)
DE Progress - Native Load Transfer Benefit	2,681,632	-	-	2,681,632	-	
DE Progress - Fees	(336)	-	-	-	(336)	
Exelon Generation Company, LLC.	139,640	-	3,738	85,180	54,460	
Haywood Electric - Economic	20,196	20,030	5	101	65	
Macquarie Energy, LLC	1,127,136	-	39,632	687,553	439,583	
NCMPA - Economic	16,800	-	400	10,248	6,552	
NCMPA Instantaneous - Economic	859,121	-	43,102	509,373	349,748	
NTE Carolinas LLC	609,000	-	24,900	371,490	237,510	
Piedmont Municipal Power Agency	284,034	-	15,447	168,404	115,630	
PJM Interconnection, LLC.	19,080	-	1,124	11,639	7,441	
South Carolina Electric & Gas Company / Dominion Energy	26,216	-	900	15,991	10,224	
Southern Company Services, Inc.	272,090	-	13,139	165,975	106,115	
Tennesse Valley Authority	185,407	-	5,372	113,098	72,309	
The Energy Authority	18,625	-	500	11,361	7,264	
Town of Dallas	584	584	-	-	-	
Town of Forest City	19,856	19,856	-	-	-	
	$ 20,779,232	**$ 253,836**	**872,300**	**$ 17,891,442**	**$ 2,634,380**	**$ (425)**
Renewable Energy						
REPS	$ 4,555,891	$ 591,922	81,362	$ -	$ 3,963,969	$ -
DERP - Purchased Power	24,691	2,168	390	-	15,590	6,933
	$ 4,580,582	**$ 594,090**	**81,752**	**$ -**	**$ 3,979,559**	**$ 6,933**
HB589 PURPA Purchases						
Qualifying Facilities	2,350,054	187,603	46,154		2,090,407	72,044
	$ 2,350,054	**$ 187,603**	**46,154**	**$ -**	**$ 2,090,407**	**$ 72,044**
Non-dispatchable / Other						
Blue Ridge Electric Membership Corp.	$ 1,330,476	$ 743,419	24,753	$ 358,105		$ 228,952
DE Progress - As Available Capacity	14,515	14,515	-	-		-
Haywood Electric	332,643	152,148	6,891	110,102		70,393
Macquarie Energy, LLC	63,800	-	1,595	38,918		24,882
NCEMC - Other	267,337	4,657	3,980	160,235		102,445
Piedmont Electric Membership Corp.	645,228	360,960	11,904	173,403		110,865
Generation Imbalance	246,069	-	4,699	70,161		175,908
Energy Imbalance - Purchases	39,310	-	1,594	31,084		8,226
Energy Imbalance - Sales	(17,924)	-	-	(17,497)		(427)
Other Purchases	524	-	15	-		524
	$ 2,921,979	**$ 1,275,700**	**55,431**	**$ 924,510**	**$ -**	**$ 721,769**
Total Purchased Power	**$ 30,631,847**	**$ 2,311,229**	**1,055,637**	**$ 18,815,952**	**$ 8,704,346**	**$ 800,320**
Interchanges In						
Other Catawba Joint Owners	7,605,405	-	711,849	4,584,919		3,020,486
WS Lee Joint Owner	394,081		11,162	305,194		88,887
Total Interchanges In	7,999,485	-	723,011	4,890,113	-	3,109,373
Interchanges Out						
Other Catawba Joint Owners	(7,451,355)	(134,209)	(692,834)	(4,464,622)		(2,852,524)
Catawba- Net Negative Generation	-	-	-	-		-
WS Lee Joint Owner	(617,693)		(20,599)	(501,976)		(115,716)
Total Interchanges Out	(8,069,048)	(134,209)	(713,433)	(4,966,598)	-	(2,968,240)
Net Purchases and Interchange Power	**$ 30,562,284**	**$ 2,177,020**	**1,065,215**	**$ 18,739,467**	**$ 8,704,346**	**$ 941,453**

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

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

DECEMBER 2019

	Total	Capacity	Non-capacity		
Sales	**$**	**$**	**mWh**	**Fuel $**	**Non-fuel $**
Utilities:					
SC Electric & Gas - Emergency	$ 31,543	-	470	$ 27,262	$ 4,281
Market Based:					
Central Electric Power Cooperative, Inc.	458,000	$ 458,000	-	-	-
NCMPA	91,985	87,500	48	4,187	298
PJM Interconnection, LLC.	168	-	-	-	168
Other:					
DE Progress - Native Load Transfer Benefit	309,999	-	-	309,999	-
DE Progress - Native Load Transfer	1,806,427	-	67,488	1,784,838	21,589
Generation Imbalance	64,487	-	2,220	42,974	21,513
BPM Transmission	-	-			-
Total Intersystem Sales	**$ 2,762,609**	**$ 545,500**	**70,226**	**$ 2,169,260**	**$ 47,849**

* Sales for resale other than native load priority.

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

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

Twelve Months Ended
December 2019

Exhibit 6
Schedule 3 - Purchases
Page 3 of 4

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Cherokee County Cogeneration Partners	$ 29,493,641	$ 10,668,301	579,750	$ 16,005,055	$ 2,820,285	
DE Progress - Native Load Transfer	118,187,137	-	5,379,774	106,969,125	11,081,282	$ 136,730
DE Progress - Native Load Transfer (Prior Period Adjust)	51,500,000	-	-	31,415,000	20,085,000	
DE Progress - Native Load Transfer Benefit	16,958,183	-	-	16,958,183	-	
DE Progress - Fees	(605,444)	-	-	-	(605,444)	
EDF Trading North America, LLC.	1,400	-	50	854	546	
Exelon Generation Company, LLC.	383,690	-	10,093	234,051	149,639	
Haywood Electric - Economic	326,963	298,730	1,612	59,547	(31,314)	
Macquarie Energy, LLC	15,963,711	-	516,706	9,737,863	6,225,848	
Morgan Stanley Capital Group	95,905	-	3,200	58,502	37,403	
NCEMC	223,880	-	9,040	136,567	87,313	
NCMPA	16,800	-	400	10,248	6,552	
NCMPA Load Following Economic	12,022,983	-	503,380	7,118,791	4,904,192	
NTE Carolinas LLC	6,091,751	-	217,073	3,715,969	2,375,782	
Piedmont Municipal Power Agency	3,235,884	-	140,334	1,902,778	1,333,106	
PJM Interconnection, LLC.	17,611,868	-	556,050	10,743,799	6,868,069	
South Carolina Electric & Gas Company / Dominion Energy	62,954	-	1,800	38,127	24,827	
Southern Company Services, Inc.	1,126,440	-	61,230	687,130	439,310	
Tennessee Valley Authority	298,582	-	10,277	182,135	116,447	
The Energy Authority	83,800	-	2,295	51,118	32,682	
Town of Dallas	7,008	7,008	-	-	-	
Town of Forest City	238,272	238,272	-	-	-	
	$ 273,325,408	**$ 11,212,311**	**7,993,064**	**$ 206,024,843**	**$ 55,951,524**	**$ 136,730**
Renewable Energy						
REPS	$ 71,364,365	$ 15,267,970	1,117,992	$ -	$ 56,096,395	$ -
DERP - Purchased Power	360,035	32,809	5,844	-	233,533	93,693
DERP - Net Metered Generation	44,824	8,197	3	-		36,627
	$ 71,769,224	**$ 15,308,976**	**1,123,838**	**$ -**	**$ 56,329,928**	**$ 130,320**
HB589 PURPA Purchases						
Qualifying Facilities	34,809,936	$ 6,969,349	580,279		$ 26,764,794	$ 1,075,793
	$ 34,809,936	**$ 6,969,349**	**580,279**	**$ -**	**$ 26,764,794**	**$ 1,075,793**
Non-dispatchable / Other						
Carolina Power & Light (DE Progress) - Emergency	$ 42,255	$ -	1,275	$ 25,775		$ 16,480
Blue Ridge Electric Membership Corp.	15,087,901	8,355,253	300,145	4,106,914		2,625,734
DE Progress - As Available Capacity	206,116	206,116	-	-		-
Haywood Electric	3,979,790	1,896,338	80,812	1,270,906		812,546
Macquarie Energy, LLC	12,796,565	-	216,547	7,805,904		4,990,661
NCEMC - Other	2,205,353	56,208	42,315	1,310,979		838,166
NCMPA - Reliability	24,800	-	400	15,128		9,672
NTE Carolinas LLC	2,437,980	-	49,870	1,487,168		950,812
Piedmont Electric Membership Corp.	7,203,245	3,969,255	140,160	1,972,735		1,261,255
Southern Company Services, Inc.	1,008,100	-	12,695	614,942		393,158
Generation Imbalance	2,122,030		83,419	1,359,973		762,057
Energy Imbalance - Purchases	571,519		(18,945)	333,736		237,783
Energy Imbalance - Sales	(1,040,510)		-	(1,337,249)		296,739
Other Purchases	11,236	-	324	-		11,236
	$ 46,656,380	**$ 14,483,170**	**909,017**	**$ 18,966,910**	**$ -**	**$ 13,206,300**
Total Purchased Power	**$ 426,560,948**	**$ 47,973,806**	**10,606,198**	**$ 224,991,753**	**$ 139,046,246**	**$ 14,549,143**
						-
Interchanges In						
Other Catawba Joint Owners	82,443,582	-	7,990,626	48,460,268		33,983,314
WS Lee Joint Owner	11,034,559	-	394,803	9,338,713		1,695,846
Total Interchanges In	93,478,141	-	8,385,428	57,798,980	-	35,679,161
Interchanges Out						
Other Catawba Joint Owners	(79,622,083)	(1,580,207)	(7,667,091)	(46,399,114)		(31,642,762)
Catawba- Net Negative Generation	(88,885)	-	(4,227)	(74,385)		(14,500)
WS Lee Joint Owner	(12,214,751)	-	(416,958)	(10,306,689)		(1,908,062)
Total Interchanges Out	(91,925,719)	(1,580,207)	(8,088,276)	(56,780,188)	-	(33,565,324)
Net Purchases and Interchange Power	**$ 428,113,370**	**$ 46,393,599**	**10,903,350**	**$ 226,010,545**	**$ 139,046,246**	**$ 16,662,980**

5

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

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

Twelve Months Ended DECEMBER 2019

	Total	Capacity	Non-capacity		
Sales	**$**	**$**	**mWh**	**Fuel $**	**Non-fuel $**
Utilities:					
DE Progress - Emergency	$ 32,606	-	1,369	$ 29,331	$ 3,275
SC Public Service Authority - Emergency	218,264	-	4,679	188,608	29,656
SC Electric & Gas - Emergency	176,126	-	4,765	155,600	20,526
Market Based:					
Central Electric Power Cooperative, Inc.	4,580,000	$ 4,580,000	-	-	-
Exelon Generation Company, LLC.	27,020	-	688	18,274	8,746
Macquarie Energy, LLC	400,050	-	10,450	282,062	117,988
NCMPA	1,265,860	1,050,350	5,692	221,824	(6,314)
PJM Interconnection, LLC.	499,356	-	13,483	386,349	113,007
SC Electric & Gas	27,383	-	505	17,942	9,441
Southern Company	9,000	-	900	13,435	(4,435)
The Energy Authority	315,490	-	6,195	176,369	139,121
Westar Energy	29,400	-	600	21,733	7,667
Other:					
DE Progress - Native Load Transfer Benefit	5,795,771	-	-	5,795,771	-
DE Progress - Native Load Transfer	54,397,949	-	1,971,074	52,117,830	2,280,119
Generation Imbalance	938,849	-	25,038	723,845	215,004
BPM Transmission	(939,967)	-		-	(939,967)
Total Intersystem Sales	**$ 67,773,157**	**$ 5,630,350**	**2,045,438**	**$ 60,148,973**	**$ 1,993,834**

* Sales for resale other than native load priority.

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

Duke Energy Carolinas

(Over) / Under Recovery of Fuel Costs
December 2019

Line No.			Residential	Commercial	Industrial	Total
1	Actual System kWh sales	Input				7,150,989,325
2	DERP Net Metered kWh generation	Input				10,508,031
3	Adjusted System kWh sales	L1 + L2				7,161,497,356
4	N.C. Retail kWh sales	Input	1,929,577,914	1,892,531,687	952,010,008	4,774,119,609
5	NC kWh sales % of actual system kWh sales	L4 T / L1				66.76%
6	NC kWh sales % of adjusted system kWh sales	L4 T / L3				66.66%
7	Approved fuel and fuel-related rates (¢/kWh)					
	7a Billed rates by class (¢/kWh)	Input Annually	1.8126	1.9561	1.8934	1.8856
	7b Lime water emissions in Base Rates	Input	0.0001	0.0001	0.0001	0.0001
	7c Total billed rates by class (¢/kWh)	L7a +L7b	1.8127	1.9562	1.8935	1.8857
	7d Billed fuel expense	L7c * L4 / 100	$34,977,459	$37,021,705	$18,026,310	$90,025,474
8	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)					
	8a Docket E-7, Sub 1190 allocation factor	Input	35.24%	42.14%	22.62%	
	8b System incurred expense	Input				$122,163,913
	8c Incurred base fuel and fuel-related expense	L8b * L6 * 8a	$28,697,516	$34,322,185	$18,419,291	$81,438,992
	8d Incurred base fuel rates by class (¢/kWh)	L8c / L4 * 100	1.4872	1.8136	1.9348	1.7058
9	Incurred renewable purchased power capacity rates by class (¢/kWh)					
	9a NC retail production plant %	Input				67.75%
	9b Production plant allocation factors	Input	44.82%	37.86%	17.32%	100.00%
	9c System incurred expense	Input				$995,058
	9d Incurred renewable capacity expense	L9a * L9b * 9c	$302,128	$255,232	$116,760	$674,120
	9e Incurred renewable capacity rates by class (¢/kWh)	(L9a * L9c) * L9b / L4 * 100	0.0157	0.0135	0.0123	0.0141
10	Total incurred rates by class (¢/kWh)	L8d + L9e	1.5029	1.8270	1.9470	1.7200
11	Difference in ¢/kWh (incurred - billed)	L7c - L10	(0.3098)	(0.1292)	0.0535	(0.1657)
12	(Over) / under recovery [See footnote]	(L4 * L11) / 100	($5,977,815)	($2,444,288)	$509,741	($7,912,362)
13	Prior period adjustments	Input	320,433	254,840	74,777	650,050
14	Total (over) / under recovery [See footnote]	L12+ L13	($5,657,382)	($2,189,448)	$584,518	($7,262,312)
15	Total system incurred expense	L8b + L9c				$123,158,971
16	Less: Jurisdictional allocation adjustment(s)	Input				341,787
17	Total Fuel and Fuel-related Costs per Schedule 2	L15 + L16				$122,817,184

18 (Over) / under recovery for each month of the current calendar year [See footnote]

			(Over) / Under Recovery			
	Year 2019	Total To Date	Residential	Commercial	Industrial	Total Company
_/1	January	$14,748,997	($326,600)	$7,761,641	$7,313,957	$14,748,997
	February	41,100,992	$5,580,727	$13,151,612	$7,619,655	26,351,995
_/1	March	47,589,069	946,440	3,110,115	2,431,522	6,488,077
	April	48,435,217	2,839,260	(884,254)	(1,108,857)	846,148
_/1	May	62,229,755	8,673,370	3,019,902	2,101,265	13,794,538
	June	66,742,620	2,477,447	(43,029)	2,078,447	4,512,865
	July	91,969,270	7,865,439	9,604,973	7,756,238	25,226,650
	August	107,565,771	4,555,238	5,409,863	5,631,400	15,596,501
_/2	September	116,902,262	3,397,342	2,224,259	3,714,890	9,336,491
_/2	October	110,532,957	($176,470)	($5,747,964)	($444,872)	(6,369,305)
	November	$116,651,736	5,149,854	340,996	627,928	6,118,779
_/1	December	$109,389,424	($5,657,382)	($2,189,448)	$584,518	(7,262,312)
			$35,324,665	$35,758,666	$38,306,091	$109,389,424

Notes:

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

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

_/1 Includes prior period adjustments.
_/2 Reflects a prorated rate and prorated allocation factor for periods in which the approved rates changed.

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
DECEMBER 2019

Description	Allen Steam	Belews Creek Steam	Buck CC	Catawba Nuclear	(A) Clemson CHP	Cliffside Steam - Dual Fuel	Dan River CC	Lee CC
Cost of Fuel Purchased ($)								
Coal	$2,320,199	$16,549,328				$13,627,538		
Oil	45,499	583,901	-			169,053	-	-
Gas - CC			$9,970,150				$8,074,155	$14,230,745
Gas - CHP					$54,658			
Gas - CT								
Gas - Steam						1,596,029		
Biogas			357,518				-	-
Total	$2,365,698	$17,133,228	$10,327,668		$54,658	$15,392,619	$8,074,155	$14,230,745
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	312.30	260.57				322.87	-	
Oil	1,484.49	1,485.00				1,474.58		
Gas - CC			348.16				345.25	347.45
Gas - CHP					388.57			
Gas - CT								
Gas - Steam						355.78		
Biogas			2,336.72			.	-	-
Weighted Average	317.12	268.11	358.73		388.57	328.85	345.25	347.45
Cost of Fuel Burned ($)								
Coal	$779,034	$10,953,735				$2,204,005	-	-
Oil - CC			-				-	-
Oil - Steam/CT	39,704	459,597				149,115		
Gas - CC			$9,970,150				$8,074,155	$14,230,745
Gas - CHP					$54,658			
Gas - CT								
Gas - Steam						1,596,029		
Biogas			357,518				-	-
Nuclear				$10,342,435				
Total	$818,738	$11,413,332	$10,327,668	$10,342,435	$54,658	$3,949,150	$8,074,155	$14,230,745
Average Cost of Fuel Burned (¢/MBTU)								
Coal	315.64	307.81				300.49		
Oil - CC								
Oil - Steam/CT	1,441.18	1,476.29				1,454.79		
Gas - CC			348.16				345.25	347.45
Gas - CHP					388.57			
Gas - CT								
Gas - Steam						355.78		
Biogas			2,336.72				-	-
Nuclear				59.29				
Weighted Average	328.06	317.95	358.73	59.29	388.57	331.21	345.25	347.45
Average Cost of Generation (¢/kWh)								
Coal	4.67	2.92				2.59	-	-
Oil - CC			-				-	-
Oil - Steam/CT	18.01	13.63				15.25	-	-
Gas - CC			2.47				2.54	2.42
Gas - CHP					-			
Gas - CT								
Gas - Steam						6.17		
Biogas			16.55				-	-
Nuclear				0.59				
Weighted Average	4.85	3.02	2.54	0.59	-	3.53	2.54	2.42
Burned MBTU's								
Coal	246,812	3,558,552				733,480		
Oil - CC								
Oil - Steam/CT	2,755	31,132				10,250		
Gas - CC			2,863,693				2,338,618	4,095,789
Gas - CHP					14,066			
Gas - CT								
Gas - Steam						448,605		
Biogas			15,300				-	-
Nuclear				17,444,528				
Total	249,567	3,589,684	2,878,993	17,444,528	14,066	1,192,335	2,338,618	4,095,789
Net Generation (mWh)								
Coal	16,667	374,612				84,991		
Oil - CC								
Oil - Steam/CT	220	3,371				978	-	-
Gas - CC			404,369				317,530	588,459
Gas - CHP					(243)			
Gas - CT								
Gas - Steam						25,886		
Biogas			2,160				-	-
Nuclear 100%				1,745,157				
Hydro (Total System)								
Solar (Total System)								
Total	16,887	377,983	406,529	1,745,157	(243)	111,855	317,530	588,459
Cost of Reagents Consumed ($)								
Ammonia		($183,864)	$16,314			$66,338	$3,702	$21,144
Limestone	$25,696	303,305				95,536		
Sorbents	-	58,214						
Urea	4,616							
Re-emission Chemical		-						
Dibasic Acid	-							
Activated Carbon	-							
Lime (water emissions)	-	-						
Total	30,312	$177,655	$16,314			$161,875	$3,702	$21,144

(A) Clemson CHP fuel and fuel related costs represents pre-commercial generation.

Notes:

Detail amounts may not add to totals shown due to rounding.
Data is reflected at 100% ownership.
Schedule excludes in-transit and terminal activity.
Cents/MBTU and cents/kWh are not computed when costs and/or net generation is negative.
Re-emission chemical reagent expense is not recoverable in NC.
Lime (water emissions) expense is not recoverable in SC fuel clause.

Lee Steam/CT	Lincoln CT	Marshall Steam	McGuire Nuclear	Mill Creek CT	Oconee Nuclear	Rockingham CT	Current Month	Total 12 ME December 2019
		$20,011,016					$52,508,080	$694,060,992
-	-	432,089		-		-	1,230,541	14,547,822
							32,275,050	337,722,147
							54,658	54,658
25,901	$68,436			$192,900		$2,023,495	2,310,732	40,328,338
338							1,596,367	42,380,517
							357,518	2,384,026
$26,239	$68,436	$20,443,105		$192,900		$2,023,495	$90,332,946	$1,131,478,500
		266.90					279.12	331.80
-	-	1,494.26		-		-	1,486.77	1,468.54
							346.85	338.43
							388.57	388.57
806.33	375.36			348.46		354.79	357.07	331.44
689.92							355.82	359.19
							2,336.72	1,927.92
806.37	375.36	271.62		348.46		354.79	308.11	338.70
-		$21,915,155					$35,851,930	$688,831,904
							-	-
90,169	$7,968	354,592		157,369		-	1,258,516	14,686,684
							32,275,050	337,722,147
							54,658	54,658
$25,901	68,436			$192,900		$2,023,495	2,310,732	40,328,338
338							1,596,367	42,380,517
							357,518	2,384,026
			$10,463,884		$9,943,647		30,749,966	364,625,765
$116,408	$76,404	$22,269,748	$10,463,884	$350,270	$9,943,647	$2,023,495	$104,454,736	$1,491,014,039
-		307.76					307.49	342.88
							-	-
1,687.29	1,511.97	1,468.41		1,794.00		-	1,517.60	1,487.46
							346.85	338.43
							388.57	388.57
806.33	375.36			348.46		354.79	357.07	331.44
689.92							355.82	359.19
							2,336.72	1,927.92
			59.52		58.32		59.05	59.06
1,353.90	407.29	311.69	59.52	546.19	58.32	354.79	140.70	158.08
-	-	2.99					2.97	3.29
							-	-
74.78	31.02	14.62		24.66		-	16.18	15.00
							2.46	2.40
							6.27	3.66
29.97	9.22			4.71		3.91	4.08	3.80
	-						6.27	3.66
							16.55	13.75
			0.59		0.59		0.59	0.60
-	9.95	3.03	0.59	7.40	0.59	3.91	1.31	1.49
-		7,120,799					11,659,643	200,898,297
							-	-
5,344	527	24,148		8,772		-	82,928	987,366
							9,298,100	99,790,482
							14,066	14,066
3,212	18,232			55,358		570,335	647,137	12,167,439
42							448,647	11,798,774
							15,300	123,658
			17,579,448		17,048,868		52,072,844	617,400,818
8,598	18,759	7,144,947	17,579,448	64,130	17,048,868	570,335	74,238,665	943,180,900
		731,886					1,208,156	20,916,177
							-	-
121	26	2,426		638		-	7,779	97,907
-							1,310,358	14,049,112
							(243)	(243)
86	742			4,095		51,698	56,622	1,062,059
(415)							25,471	1,157,313
							2,160	17,335
			1,771,567		1,687,079		5,203,803	61,066,543
							171,008	1,713,885
							8,911	142,127
(208)	768	734,312	1,771,567	4,733	1,687,079	51,698	7,994,025	100,222,215
							($76,367)	$3,302,749
		$537,641					962,178	18,302,336
		168,388					226,602	2,001,326
		40,024					44,639	590,744
							-	284,446
							-	-
		-					-	171,399
		11,061					11,061	277,536
		$757,113					$1,168,113	$24,930,536

(A) Clemson CHP fuel and fuel related costs represents pre-commercial generation.

Notes:

Detail amounts may not add to totals shown due to rounding.
Data is reflected at 100% ownership.
Schedule excludes in-transit and terminal activity.
Cents/MBTU and cents/kWh are not computed when costs and/or net generation is negative.
Re-emission chemical reagent expense is not recoverable in NC.
Lime (water emissions) expense is not recoverable in SC fuel clause.

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED CONSUMPTION AND INVENTORY REPORT
DECEMBER 2019

Exhibit 6
Schedule 6

Description	Allen Steam	Belews Creek Steam	Buck CC	(A) Clemson CHP	Cliffside Steam - Dual Fuel	Dan River CC	Lee CC	Lee Steam/CT	Lincoln CT	Marshall Steam	Mill Creek CT	Rockingham CT	Current Month	Total 12 ME December 2019
Coal Data:														
Beginning balance	137,735	789,951			414,459			-		484,089			1,826,234	1,799,939
Tons received during period	34,735	254,637			190,358					283,764			763,494	8,452,675
Inventory adjustments	(4,081)	0			(14,803)			-		24,397			5,514	4,123
Tons burned during period	10,271	143,490			29,561			-		284,097			467,419	8,128,914
Ending balance	158,118	901,099			560,453			-		508,153			2,127,823	2,127,823
MBTUs per ton burned	24.03	24.80			24.81			-		25.06			24.94	24.71
Cost of ending inventory ($/ton)	75.85	76.34			74.56			-		77.58			76.13	76.13
Oil Data:														
Beginning balance	102,100	131,858	-		194,655	-	-	603,811	9,716,597	304,891	4,366,782	3,133,258	18,553,952	18,866,098
Gallons received during period	22,210	284,927	-		83,076	-	-	-	-	209,541	-	-	599,754	7,177,481
Miscellaneous adjustments	-	(15,752)	-		(6,298)	-	-	-	-	-	-	-	(21,788)	(348,465)
Gallons burned during period	19,946	225,569			74,062	-	-	38,747	3,802	174,735	63,729	-	600,852	7,164,048
Ending balance	104,364	175,464	-		197,371	-	-	565,064	9,712,795	339,697	4,303,053	3,133,258	18,531,066	18,531,066
Cost of ending inventory ($/gal)	1.99	2.04	-		2.01	-	-	2.33	2.10	2.03	2.47	2.17	2.20	2.20
Natural Gas Data:														
Beginning balance														
MCF received during period			2,782,442	13,697	435,568	2,273,527	3,987,068	3,180	17,791		54,015	552,382	10,119,670	120,302,953
MCF burned during period			2,782,442	13,697	435,568	2,273,527	3,987,068	3,180	17,791		54,015	552,382	10,119,670	120,302,953
Ending balance														
Biogas Data:														
Beginning balance														
MCF received during period			14,866			-	-						14,866	119,928
MCF burned during period			14,866			-	-						14,866	119,928
Ending balance														
Limestone Data:														
Beginning balance	22,816	54,598			11,341					73,350			162,105	115,155
Tons received during period	-	6,490			24,491					12,544			43,525	494,449
Inventory adjustments	(2,613)	-			(3,593)					-			(6,206)	(6,206)
Tons consumed during period	499	6,988			1,881					14,137			23,505	427,479
Ending balance	19,704	54,100			30,357					71,757			175,919	175,919
Cost of ending inventory ($/ton)	51.45	40.04			42.07					38.03			40.85	40.85

Description	Allen Steam	Belews Creek Steam	Qtr Ending December 2019	Total 12 ME December 2019
Ammonia Data:				
Beginning balance		1,189	1,189	1,644
Tons received during period		843	843	3,499
Tons consumed during period		627	627	3,738
Ending balance		1,405	1,405	1,405
Cost of ending inventory ($/ton)		517.74	517.74	517.74

(A) Clemson CHP fuel and fuel related consumption represents precommercial activity.

Notes:

Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit and terminal activity.
Gas is burned as received; therefore, inventory balances are not maintained.

Exhibit 6
Schedule 7

DUKE ENERGY CAROLINAS

ANALYSIS OF COAL PURCHASED

DECEMBER 2019

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ALLEN	SPOT	23,706	$ 1,377,986	$ 58.13
	CONTRACT	11,029	827,865	75.06
	FIXED TRANSPORTATION / ADJUSTMENTS	-	114,347	-
	TOTAL	34,735	2,320,199	75.69
BELEWS CREEK	SPOT	38,356	2,182,955	56.91
	CONTRACT	216,282	13,798,961	63.80
	FIXED TRANSPORTATION / ADJUSTMENTS	-	567,412	-
	TOTAL	254,637	16,549,328	64.99
CLIFFSIDE	SPOT	50,520	3,491,815	69.12
	CONTRACT	139,838	9,584,744	68.54
	FIXED TRANSPORTATION / ADJUSTMENTS	-	550,979	-
	TOTAL	190,358	13,627,538	77.63
MARSHALL	SPOT	89,954	5,627,671	62.56
	CONTRACT	193,810	13,360,215	68.93
	FIXED TRANSPORTATION / ADJUSTMENTS	-	1,023,130	-
	TOTAL	283,764	20,011,016	65.23
ALL PLANTS	SPOT	202,536	12,680,427	62.61
	CONTRACT	560,959	37,571,785	66.98
	FIXED TRANSPORTATION / ADJUSTMENTS	-	2,255,868	-
	TOTAL	763,494	$ 52,508,080	$ 68.77

Exhibit 6

Schedule 8

DUKE ENERGY CAROLINAS

ANALYSIS OF COAL QUALITY RECEIVED

DECEMBER 2019

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
ALLEN	6.58	12.60	12,118	0.88
BELEWS CREEK	7.02	10.00	12,471	1.64
CLIFFSIDE	10.18	9.40	12,021	1.91
MARSHALL	6.85	11.48	12,220	1.23

DUKE ENERGY CAROLINAS

ANALYSIS OF OIL PURCHASED

DECEMBER 2019

	ALLEN	BELEWS CREEK
VENDOR	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract
SULFUR CONTENT %	0	0
GALLONS RECEIVED	22,210	284,927
TOTAL DELIVERED COST	$ 45,499	$ 583,901
DELIVERED COST/GALLON	$ 2.05	$ 2.05
BTU/GALLON	138,000	138,000

	CLIFFSIDE	MARSHALL
VENDOR	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract
SULFUR CONTENT %	0	0
GALLONS RECEIVED	83,076	209,541
TOTAL DELIVERED COST	$ 169,053	$ 432,089
DELIVERED COST/GALLON	$ 2.03	$ 2.06
BTU/GALLON	138,000	138,000

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period Sept 2020 through Aug 2021
Docket E-7, Sub 1228

McGee Workpaper 1

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs	9,994,379	9,007,229	9,179,320	9,949,902	6,585,428	7,276,686	7,371,013	59,363,957
Cost (Gross of Joint Owners)	$ 61,864,018	$ 57,191,501	$ 53,296,002	$ 60,341,229	$ 41,461,273	$ 42,351,267	$ 42,092,026	358,597,316
$/MWh	6.1899	6.3495	5.8061	6.0645	6.2959	5.8201	5.7105	
Avg $/MWh		**6.0407**						
Cents per kWh		**0.6041**						

			Sept 2020 - August 2021
MDC			
CATA_UN01	Catawba	MW	1,160.1
CATA_UN02	Catawba	MW	1,150.1
MCGU_UN01	McGuire	MW	1,158.0
MCGU_UN02	McGuire	MW	1,157.6
OCON_UN01	Oconee	MW	847.0
OCON_UN02	Oconee	MW	848.0
OCON_UN03	Oconee	MW	859.0
			7,179.8
Hours in month			8,760
Generation GWHs			
CATA_UN01	Catawba	GWh	9,994
CATA_UN02	Catawba	GWh	9,007
MCGU_UN01	McGuire	GWh	9,179
MCGU_UN02	McGuire	GWh	9,950
OCON_UN01	Oconee	GWh	6,585
OCON_UN02	Oconee	GWh	7,277
OCON_UN03	Oconee	GWh	7,371
			59,364
	Proposed Nuclear Capacity Factor		94.39%

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period Sept 2020 through Aug 2021
Docket E-7, Sub 1228

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs with NERC applied	9,281,389	9,201,384	9,264,588	9,261,388	6,833,562	6,841,630	6,930,378	57,614,320
Hours	8760	8760	8760	8760	8760	8760	8760	8760
MDC	1160.1	1150.1	1158.0	1157.6	847.0	848.0	859.0	7179.8
Capacity factor	91.33%	91.33%	91.33%	91.33%	92.10%	92.10%	92.10%	91.60%
Cost	$ 56,065,691	$ 55,582,408	$ 55,964,202	$ 55,944,871	$ 41,279,206	$ 41,327,942	$ 41,864,036	$ 348,028,357

Avg $/MWh		**6.0407**
Cents per kWh		**0.6041**

2014-2018	Capacity Rating	NCF Rating	Weighted Average	
Oconee 1	847.0	92.10	10.87%	
Oconee 2	848.0	92.10	10.88%	
Oconee 3	859.0	92.10	11.02%	
McGuire 1	1158.0	91.33	14.73%	
McGuire 2	1157.6	91.33	14.73%	
Catawba 1	1160.1	91.33	14.76%	
Catawba 2	1150.1	91.33	14.63%	
	7179.8		**91.60%**	Wtd Avg on Capacity Rating

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation and Purchased Power in MWhs
Billing Period Sept 2020 through Aug 2021
Docket E-7, Sub 1228

McGee Workpaper 3

Resource Type	Sept 2020 - August 2021	
NUC Total (Gross)	59,363,957	
COAL Total	14,450,043	
Gas CT and CC total (Gross)	25,505,409	
Run of River	4,305,885	
Net pumped Storage	(3,219,894)	
Total Hydro	1,085,991	
Catawba Joint Owners	(14,848,200)	
Lee CC Joint Owners	(876,000)	
DEC owned solar	385,094	
Total Generation		85,066,294
Purchases for REPS Compliance	1,178,490	
Qualifying Facility Purchases - Non-REPS compliance	1,457,406	
Other Purchases	55,260	
Allocated Economic Purchases	281,308	
Joint Dispatch Purchases	5,314,338	
	8,286,802	
Total Generation and Purchased Power		93,353,096
Fuel Recovered Through intersystem Sales	(1,024,819)	

DUKE ENERGY CAROLINAS **McGee Workpaper 4**
North Carolina Annual Fuel and Fuel Related Expense
Projected Fuel and Fuel Related Costs
Billing Period Sept 2020 through Aug 2021
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Resource Type	Sept 2020 - August 2021	
Nuclear Total (Gross)	$ 358,597,316	
COAL Total	394,529,148	
Gas CT and CC total (Gross)	583,236,234	
Catawba Joint Owner costs	(89,710,135)	
CC Joint Owner costs	(16,315,588)	
Non-Economic Fuel Expense Recovered through Reimbursement	(20,370,677)	
Reagents and gain/loss on sale of By-Products	22,532,174	Workpaper 9
Purchases for REPS Compliance - Energy	63,001,495	
Purchases for REPS Compliance Capacity	13,122,631	
Purchases of Qualifying Facilities - Energy	56,445,045	
Purchases of Qualifying Facilities - Capacity	12,285,396	
Other Purchases	1,628,569	
JDA Savings Shared	14,281,717	Workpaper 5
Allocated Economic Purchase cost	7,049,441	Workpaper 5
Joint Dispatch purchases	105,078,276	Workpaper 6
Total Purchases	272,892,569	
Fuel Expense recovered through intersystem sales	(21,248,787)	Workpaper 5
Total System Fuel and Fuel Related Costs	**$ 1,484,142,254**	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected Joint Dispatch Fuel Impacts
Billing Period Sept 2020 through Aug 2021
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McGee Workpaper 5

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	
	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC
9/1/2020	$ 150,586	$ 218,086	$ (186,875)	$ (1,877)	$ (11,497,078)	$ 11,497,078	$ (1,975,776)	$ 1,975,776
10/1/2020	$ 265,863	$ 393,719	$ (14,356)	$ (18,503)	$ (12,216,995)	$ 12,216,995	$ (4,360,326)	$ 4,360,326
11/1/2020	$ 240,709	$ 352,454	$ (113,164)	$ (144,187)	$ (9,859,588)	$ 9,859,588	$ (1,221,763)	$ 1,221,763
12/1/2020	$ 305,584	$ 439,721	$ (344,748)	$ (156,339)	$ (6,964,610)	$ 6,964,610	$ (728,229)	$ 728,229
1/1/2021	$ 555,450	$ 797,270	$ (2,223,855)	$ (5,361,748)	$ (1,671,260)	$ 1,671,260	$ 438,172	$ (438,172)
2/1/2021	$ 276,329	$ 404,845	$ (1,175,462)	$ (2,653,321)	$ (1,478,925)	$ 1,478,925	$ 252,213	$ (252,213)
3/1/2021	$ 115,648	$ 173,267	$ (267,648)	$ (249,022)	$ (4,669,706)	$ 4,669,706	$ (519,291)	$ 519,291
4/1/2021	$ 322,509	$ 493,555	$ (59,771)	$ (13,472)	$ (9,219,652)	$ 9,219,652	$ (2,086,290)	$ 2,086,290
5/1/2021	$ 259,850	$ 377,118	$ (169,035)	$ (150,799)	$ (3,269,361)	$ 3,269,361	$ (246,015)	$ 246,015
6/1/2021	$ 477,664	$ 655,788	$ (147,998)	$ (159,459)	$ (7,563,783)	$ 7,563,783	$ (808,172)	$ 808,172
7/1/2021	$ 703,253	$ 985,552	$ (337,183)	$ (358,756)	$ (12,505,842)	$ 12,505,842	$ (1,506,194)	$ 1,506,194
8/1/2021	$ 1,218,853	$ 1,758,065	$ (148,196)	$ (46,457)	$ (12,226,627)	$ 12,226,627	$ (1,520,045)	$ 1,520,045
Sept 20 - Aug 21		$ 7,049,441		$ (9,313,939)		$ 93,143,428		$ 14,281,717

$ 105,078,276	Workpaper 6 - Transfer - Purchases
$ (11,934,848)	Workpaper 6 - Transfer - Sales
$ 93,143,428	Sept 20-Aug 21 Net Fuel Transfer Payment
$ (11,934,848)	Workpaper 6 - Transfer - Sales
$ (9,313,939)	Sept 20-Aug 21 Economic Sales Cost
$ (21,248,787)	**Total Fuel expense recovered through intersystem sales**

rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected Merger Payments
Billing Period Sept 2020 through Aug 2021
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McGee Workpaper 6

	Transfer Projection		Purchase Allocation Delta		Adjusted Transfer		Fossil Gen Cost		Pre-Net Payments	
					purchase	sale			sale	purchase
	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC
9/1/2020	601,189	4,198	4,350	(4,350)	605,539	4,198	$ 19.08	$ 13.30	$ 55,829	$ 11,552,907
10/1/2020	653,593	3,556	7,218	(7,218)	660,811	3,556	$ 18.56	$ 13.50	$ 47,994	$ 12,264,989
11/1/2020	530,630	18,110	2,987	(2,987)	533,617	18,110	$ 18.88	$ 11.80	$ 213,758	$ 10,073,345
12/1/2020	400,257	109,359	(5,683)	5,683	400,257	115,042	$ 21.51	$ 14.30	$ 1,644,589	$ 8,609,199
1/1/2021	166,669	137,750	(8,797)	8,797	166,669	146,548	$ 22.43	$ 14.10	$ 2,066,735	$ 3,737,995
2/1/2021	154,232	132,870	(8,082)	8,082	154,232	140,952	$ 22.08	$ 13.67	$ 1,926,765	$ 3,405,690
3/1/2021	311,996	93,958	(2,597)	2,597	311,996	96,555	$ 18.94	$ 12.85	$ 1,240,748	$ 5,910,454
4/1/2021	557,710	41,790	(4,430)	4,430	557,710	46,219	$ 17.89	$ 16.43	$ 759,226	$ 9,978,878
5/1/2021	304,500	124,561	(7,146)	7,146	304,500	131,707	$ 17.27	$ 15.11	$ 1,989,875	$ 5,259,237
6/1/2021	442,810	81,622	3,624	(3,624)	446,434	81,622	$ 19.72	$ 15.21	$ 1,241,824	$ 8,805,608
7/1/2021	576,231	29,031	13,298	(13,298)	589,529	29,031	$ 22.01	$ 16.18	$ 469,663	$ 12,975,505
8/1/2021	549,883	17,473	33,160	(33,160)	583,043	17,473	$ 21.45	$ 15.90	$ 277,841	$ 12,504,469
Sept 20 - Aug 21	5,249,701	794,279	27,902	(27,902)	5,314,338	831,014			$ 11,934,848	$ 105,078,276
									Net Pre-Net Payments	$ 93,143,428

rounding differences may occur

DUKE ENERGY CAROLINAS **McGee Workpaper 7**
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 94.39%
Billing Period Sept 2020 through Aug 2021
Docket E-7, Sub 1228

Fall 2019 Forecast
Billed Sales Forecast
Sales Forecast - MWhs (000)

		Projected sales for the Billing Period	Remove impact of SC DERP Net Metered generation	Adjusted Sales
North Carolina:				
	Residential	22,067,951		22,067,951
	General	23,677,896		23,677,896
	Industrial	12,441,023		12,441,023
	Lighting	273,219		273,219
	NC RETAIL	58,460,089	-	58,460,089
South Carolina:				
	Residential	6,628,994	90,021	6,719,015
	General	5,939,271	71,593	6,010,863
	Industrial	9,134,820	514	9,135,334
	Lighting	45,590	-	45,590
	SC RETAIL	21,748,675	162,127	21,910,802
Total Retail Sales				
	Residential	28,696,946	90,021	28,786,966
	General	29,617,166	71,593	29,688,759
	Industrial	21,575,843	514	21,576,357
	Lighting	318,809	-	318,809
	Retail Sales	80,208,764	162,127	80,370,891
	Wholesale	8,174,475	-	8,174,475
	Projected System MWH Sales for Fuel Factor	88,383,239	162,127	88,545,366
	NC as a percentage of total	**66.14%**		**66.02%**
	SC as a percentage of total	24.61%		24.75%
	Wholesale as a percentage of total	9.25%		9.23%
		100.00%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	162,127
Marginal fuel rate per MWh for SC NEM	$ 32.53
Fuel benefit to be directly assigned to SC Retail	$ 5,273,991

System Fuel Expense	$ 1,484,142,254	McGee Exhibit 2 Schdule 1 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 5,273,991	
Total Fuel Costs for Allocation	$ 1,489,416,245	McGee Exhibit 2 Schdule 1 Page 3 of 3, L5

Reconciliation

	System	NC Retail Customers	Wholesale	South Carolina Retail	
Total system fuel expense from McGee Exhibit 2 Schedule 1 Page 1	$ 1,484,142,254				
QF and REPS Compliance Purchased Power - Capacity	$ 25,408,027				
Other fuel costs	$ 1,458,734,227				
SC Net Metering Fuel Allocation adjustment	$ 5,273,991				
Jurisdictional fuel costs after adj.	$ 1,464,008,218				
Allocation to states/classes		66.02%	9.23%	24.75%	
Jurisdictional fuel costs	$ 1,464,008,218	$ 966,538,226	$ 135,127,959	$ 362,342,034	67.55% Capacity Allocator
Direct Assignment of Fuel benefit to SC Retail	$ (5,273,991)		$ -	$ (5,273,991)	
Total system actual fuel costs	$ 1,458,734,227	$ 966,538,226	$ 135,127,959	$ 357,068,043	
QF and REPS Compliance Purchased Power - Capacity	25,408,027	17,162,430			
Total system fuel expense from McGee Exhibit 2 Schedule 1 Page 1	$ 1,484,142,254	**$ 983,700,656**			
		Exh.2, Sch. 1 page 3, Line 13			

DUKE ENERGY CAROLINAS **Revised McGee Workpaper 7a**
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 94.39% and Normalized Test Period Sales
Billing Period Sept 2020 through Aug 2021
Docket E-7, Sub 1228

Fall 2019 Forecast
Billed Sales Forecast - Normalized Test Period Sales
Sales Forecast - MWhs (000)

		Test Period Sales	Customer Growth Adjustment	Weather Adjustment	Remove impact of SC DERP Net Metered generation	Normalized Test Period Sales
North Carolina:						
	NC RETAIL	58,642,521	296,714	(316,696)	-	58,622,539
South Carolina:						
	SC RETAIL	21,466,517	86,091	4,841	162,127	21,719,576
	Wholesale	7,802,295	72,243	76,245	-	7,950,783
	Normalized System MWH Sales for Fuel Factor	87,911,333	455,048	(235,610)	162,127	88,292,898
	NC as a percentage of total	**66.71%**				**66.40%**
	SC as a percentage of total	24.42%				24.60%
	Wholesale as a percentage of total	8.88%				9.01%
		100.00%				100.01%

SC Net Metering allocation adjustment		
Total projected SC NEM MWhs	162,127	
Marginal fuel rate per MWh for SC NEM	$ 32.53	
Fuel benefit to be directly assigned to SC Retail	$ 5,273,991	
System Fuel Expense	$ 1,477,249,132	McGee Exhibit 2 Schedule 2 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 5,273,991	
Total Fuel Costs for Allocation	$ 1,482,523,124	McGee Exhibit 2 Schedule 2 Page 3 of 3, L5

Reconciliation	System	NC Retail Customers	Wholesale	South Carolina Retail
Total system fuel expense from McGee Exhibit 2 Schedule 2 Page 1	$ 1,477,249,132			
QF and REPS Compliance Purchased Power - Capacity	$ 25,408,027			
Other fuel costs	$ 1,451,841,105			
SC Net Metering Fuel Allocation adjustment	$ 5,273,991			
Jurisdictional fuel costs after adj.	$ 1,457,115,097			
Allocation to states/classes		66.40%	9.01%	24.60%
Jurisdictional fuel costs	$ 1,457,115,097	$ 967,524,424	$ 131,286,070	$ 358,450,314
Direct Assignment of Fuel benefit to SC Retail	$ (5,273,991)		$ -	$ (5,273,991)
Total system actual fuel costs	$ 1,451,841,105	$ 967,524,424	$ 131,286,070	$ 353,176,322
QF and REPS Compliance Purchased Power - Capacity	25,408,027	17,162,430		
Total system fuel expense from McGee Exhibit 2 Schedule 2 Page 1	$ 1,477,249,132	**$ 984,686,854**		
		Exh. 2, Sch 2 page 3, Line 13		

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
NERC 5 Year Average Nuclear Capacity Factor of 91.60%
Billing Period Sept 2020 through Aug 2021
Docket E-7, Sub 1228

McGee Workpaper 7b

Fall 2019 Forecast
Billed Sales Forecast
Sales Forecast - MWhs (000)

		Projected sales for the Billing Period	Remove impact of SC DERP Net Metered generation	Adjusted Sales
North Carolina:				
	Residential	22,067,951		22,067,951
	General	23,677,896		23,677,896
	Industrial	12,441,023		12,441,023
	Lighting	273,219		273,219
	NC RETAIL	58,460,089	-	58,460,089
South Carolina:				
	Residential	6,628,994	90,021	6,719,015
	General	5,939,271	71,593	6,010,863
	Industrial	9,134,820	514	9,135,334
	Lighting	45,590	0	45,590
	SC RETAIL	21,748,675	162,127	21,910,802
Total Retail Sales				
	Residential	28,696,946	90,021	28,786,966
	General	29,617,166	71,593	29,688,759
	Industrial	21,575,843	514	21,576,357
	Lighting	318,809	-	318,809
	Retail Sales	80,208,764	162,127	80,370,891
	Wholesale	8,174,475	-	8,174,475
	Projected System MWh Sales for Fuel Factor	88,383,239	162,127	88,545,366
	NC as a percentage of total	**66.14%**		**66.02%**
	SC as a percentage of total	24.61%		24.75%
	Wholesale as a percentage of total	9.25%		9.23%
		100.00%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	162,127	
Marginal fuel rate per MWh for SC NEM	$ 32.53	
Fuel benefit to be directly assigned to SC Retail	$ 5,273,998	
System Fuel Expense	$ 1,512,039,261	McGee Exhibit 2 Schedule 3 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 5,273,998	
Total Fuel Costs for Allocation	$ 1,517,313,259	McGee Exhibit 2 Schedule 3 Page 3 of 3, Line 5

Reconciliation

	System	NC Retail Customers	Wholesale	South Carolina Retail
Total system fuel expense from McGee Exhibit 2 Schedule 3 Page 1	$ 1,512,039,261			
QF and REPS Compliance Purchased Power - Capacity	$ 25,408,027			
Other fuel costs	$ 1,486,631,234			
SC Net Metering Fuel Allocation adjustment	$ 5,273,998			
Jurisdictional fuel costs after adj.	$ 1,491,905,232			
Allocation to states/classes		66.02%	9.23%	24.75%
Jurisdictional fuel costs	$ 1,491,905,232	$ 984,955,834	$ 137,702,853	$ 369,246,545
Direct Assignment of Fuel benefit to SC Retail	$ (5,273,998)		$ -	$ (5,273,998)
Total system actual fuel costs	$ 1,486,631,234	$ 984,955,834	$ 137,702,853	$ 363,972,547
QF and REPS Compliance Purchased Power - Capacity	25,408,027	17,162,430		
Total system fuel expense from McGee Exhibit 2 Schedule 3 Page 1	$ 1,512,039,261	**$ 1,002,118,264**		
		Exh. 2, Sch.3 page 3, Line 13		

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Annualized Revenue
Billing Period Sept 2020 through Aug 2021
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McGee Workpaper 8

	January 2020 Actuals			Normalized Sales	
	Revenue	**KWH Sales**	**Cents/ kwh**	**McGee EX 4**	**Total Annualized Revenues**
	(a)	(b)	(a) / (b) *100 = (c)	(d)	(c) * (d) * 10
Residential	$ 205,510,334.69	2,021,126,178	10.1681	22,444,481	$ 2,282,179,536
General	$ 144,495,008.55	1,919,161,419	7.5291	23,688,550	$ 1,783,527,535
Industrial	$ 48,720,309.60	858,762,556	5.6733	12,489,508	$ 708,569,199
Total	$ 398,725,652.84	4,799,050,153		58,622,539	$ 4,774,276,270

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected Reagents and ByProducts
Billing Period Sept 2020 through Aug 2021
Docket E-7, Sub 1228

Reagent and ByProduct projections

Date	Ammonia	Urea	Limestone	Magnesium hydroxide	Calcium Carbonate	Lime	Reagent Cost	Gypsum (Gain)/ Loss	Ash (Gain)/Loss	Steam (Gain)/Loss	Sale of By-Products (Gain)/Loss
9/1/2020	$ 233,500	$ 40,858	$ 1,291,541	$ 173,825	$ 89,742	$ 59,960	**$ 1,889,426**	$ 358,811	$ (33,145)	$ (80,084)	**$ 245,582**
10/1/2020	$ 188,501	$ 32,984	$ 1,042,637	$ 71,908	$ 42,872	$ 59,960	**$ 1,438,861**	$ 290,184	$ (13,557)	$ (79,927)	**$ 196,699**
11/1/2020	$ 198,004	$ 34,647	$ 1,095,204	$ 137,550	$ 71,592	$ 59,960	**$ 1,596,957**	$ 355,932	$ (73,420)	$ (79,783)	**$ 202,728**
12/1/2020	$ 261,216	$ 45,708	$ 1,444,841	$ 228,479	$ 110,121	$ 59,960	**$ 2,150,324**	$ 509,662	$ (174,818)	$ (79,671)	**$ 255,173**
1/1/2021	$ 419,456	$ 73,397	$ 2,320,102	$ 333,985	$ 162,393	$ 59,960	**$ 3,369,293**	$ 761,396	$ (243,098)	$ (79,644)	**$ 438,654**
2/1/2021	$ 410,928	$ 71,904	$ 2,272,930	$ 333,052	$ 162,346	$ 59,960	**$ 3,311,120**	$ 726,826	$ (224,855)	$ (79,639)	**$ 422,331**
3/1/2021	$ 211,172	$ 36,951	$ 1,168,035	$ 232,231	$ 105,236	$ 59,960	**$ 1,813,585**	$ 444,465	$ (184,558)	$ (79,617)	**$ 180,291**
4/1/2021	$ 49,963	$ 8,743	$ 276,356	$ 210,962	$ 99,191	$ 59,960	**$ 705,175**	$ 85,702	$ (24,859)	$ (79,602)	**$ (18,759)**
5/1/2021	$ 36,003	$ 6,300	$ 199,141	$ 188,716	$ 90,692	$ 59,960	**$ 580,811**	$ 51,459	$ (9,663)	$ (79,599)	**$ (37,803)**
6/1/2021	$ 63,789	$ 11,162	$ 352,832	$ 282,721	$ 137,281	$ 59,960	**$ 907,746**	$ 104,580	$ (30,245)	$ (79,617)	**$ (5,281)**
7/1/2021	$ 123,135	$ 21,546	$ 681,086	$ 340,068	$ 167,985	$ 59,960	**$ 1,393,781**	$ 208,096	$ (57,134)	$ (79,632)	**$ 71,330**
8/1/2021	$ 120,576	$ 21,098	$ 666,931	$ 324,557	$ 162,092	$ 59,960	**$ 1,355,215**	$ 205,966	$ (57,385)	$ (79,647)	**$ 68,934**
	$ 2,316,243	$ 405,298	$ 12,811,635	$ 2,858,054	$ 1,401,545	$ 719,520	**$ 20,512,295**	$ 4,103,079	$ (1,126,738)	$ (956,462)	**$ 2,019,880**

Total Reagent cost and Sale of By-products **$ 22,532,174**

rounding differences may occur

DUKE ENERGY CAROLINAS **McGee Workpaper 10**
North Carolina Annual Fuel and Fuel Related Expense
2.5% calculation test
Twelve Months Ended December 31, 2019
Billing Period Sept 2020 through Aug 2021
Docket E-7, Sub 1228

Line No.	Description	Forecast $	(over)/under Collection $	Total $
1	Amount in current docket	101,750,258	1,617,020	103,367,278
2	Amount in Sub 1190, prior year docket	107,380,554	72,488,427	179,868,981
3	Increase/(Decrease)	(5,630,296)	(70,871,406)	(76,501,702)
4	2.5% of 2019 NC retail revenue of $4,869,968,814			121,749,220
	Excess of purchased power growth over 2.5% of Revenue			0
	E-7 Sub 1228			
WP 4	Purchases for REPS Compliance - Energy	63,001,495	66.02%	41,593,587
WP 4	Purchases for REPS Compliance Capacity	13,122,631	67.55%	8,863,980
WP 4	Purchases	1,628,569	66.02%	1,075,181
WP 4	QF Energy	56,445,045	66.02%	37,265,019
WP 4	QF Capacity	12,285,396	67.55%	8,298,450
WP 4	Allocated Economic Purchase cost	7,049,441	66.02%	4,654,041
		153,532,577		101,750,258
	E-7 Sub 1190			
	Purchases for REPS Compliance	63,867,566	66.16%	42,254,782
	Purchases for REPS Compliance Capacity	13,295,654	67.04%	8,912,938
	Purchases	2,029,948	66.16%	1,343,014
	QF Energy	58,754,197	66.16%	38,871,777
	QF Capacity	14,874,084	67.04%	9,971,063
	Allocated Economic Purchase cost	9,109,705	66.16%	6,026,981
		161,931,154		107,380,554

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
2.5% calculation test
Twelve Months Ended December 31, 2019
Docket E-7, Sub 1228

McGee Workpaper 10a

2019	**Jan19**	**Feb19**	**Mar19**	**Apr19**	**May19**	**June 19**	**Jul19**	**Aug19**	**Sep19**	**Oct19**	**Nov19**	**Dec19**	**12 ME**
System KWH Sales - Sch 4, Adjusted	7,570,888,821	7,430,788,664	6,521,808,145	6,367,436,322	6,726,545,218	7,552,455,357	8,316,260,504	8,548,800,472	8,292,133,918	7,019,132,212	6,533,297,016	7,161,497,356	88,041,044,005
NC Retail KWH Sales - Sch 4	5,021,049,922	5,026,972,376	4,366,363,694	4,263,829,687	4,421,389,704	5,029,188,554	5,524,188,997	5,710,820,956	5,512,226,874	4,692,561,973	4,299,808,753	4,774,119,609	58,642,521,099
NC Retail % of Sales, Adjusted (Calc)	66.32%	67.65%	66.95%	66.96%	65.73%	66.59%	66.43%	66.80%	66.48%	66.85%	65.81%	66.66%	66.61%
NC retail production plant %	67.56%	67.56%	67.56%	67.56%	67.75%	67.75%	67.75%	67.75%	67.75%	67.75%	67.75%	67.75%	67.72%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 23,687,311	$ 57,492,154	$ 14,514,026	$ 14,125,368	$ 6,227,781	$ 7,986,019	$ 9,392,534	$ 7,209,102	$ 18,620,321	$ 13,793,051	$ 15,085,734	$ 17,891,442	$ 206,024,843
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	10,050,079	26,532,896	2,706,430	4,264,779	908,542	640,701	1,230,088	1,129,642	1,974,692	1,539,252	2,340,043	2,634,380	$ 55,951,524
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	3,283,437	4,116,642	3,779,240	5,137,202	5,251,425	5,598,653	5,193,633	5,586,738	5,216,879	4,899,454	4,069,122	3,963,969	$ 56,096,394
System Actual$ - Sch 3 Fuel-related$; SC DERP	102	14,377	8,659	21,097	25,363	30,158	22,270	26,481	26,351	26,014	17,072	15,590	$ 233,534
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	1,367,422	1,711,969	1,557,910	2,135,075	2,259,422	2,837,912	2,660,982	2,749,375	2,583,768	2,605,902	2,204,650	2,090,407	$ 26,764,794
Total System Economic & QF$	38,388,351	89,868,038	22,566,265	25,683,521	14,672,533	17,093,443	18,499,507	16,701,338	28,422,011	22,863,673	23,716,621	26,595,788	345,071,089
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 11,884,171	$ 71,766,352	$ 8,909,559	$ 10,043,093	$ 3,969,493	$ 6,657,925	$ 7,676,184	$ 5,446,589	$ 17,997,075	$ 13,185,756	$ 12,864,226	$ 15,502,723	$ 185,903,146
Total System Economic $ without Native Load Transfers	$ 26,504,180	$ 18,101,686	$ 13,656,706	$ 15,640,428	$ 10,703,040	$ 10,435,518	$ 10,823,323	$ 11,254,749	$ 10,424,936	$ 9,677,917	$ 10,852,395	$ 11,093,065	$ 159,167,943
NC Actual $ (Calc)	$ 17,577,699	$ 12,245,897	$ 9,143,192	$ 10,473,308	$ 7,035,158	$ 6,949,023	$ 7,189,539	$ 7,518,465	$ 6,930,015	$ 6,470,063	$ 7,142,370	$ 7,395,049	$ 106,069,779
Billed rate (¢/kWh):	0.1922	0.1922	0.1922	0.1922	0.1922	0.1922	0.1922	0.1922	0.1759	0.1535	0.1533	0.1533	
Billed $:	$ 9,650,458	$ 9,661,841	$ 8,392,151	$ 8,195,081	$ 8,497,911	$ 9,666,100	$ 10,617,491	$ 10,976,198	$ 9,696,007	$ 7,203,083	$ 6,591,607	$ 7,318,725	$ 106,466,653
(Over)/ Under $:	$ 7,927,242	$ 2,584,056	$ 751,041	$ 2,278,227	$ (1,462,753)	$ (2,717,077)	$ (3,427,952)	$ (3,457,733)	$ (2,765,992)	$ (733,020)	$ 550,763	$ 76,323	$ (396,874)
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ 426,732	$ 426,732	$ 213,366	$ 213,366	$ 320,050	$ 1,386,879	$ 3,200,490	$ 3,200,490	$ 640,098	$ 213,366	$ 213,366	$ 213,366	$ 10,668,301
System Actual $ - Capacity component of Purchased Power for REPS Compliance	608,844	738,655	747,764	827,415	781,129	817,587	2,308,343	2,605,889	2,449,375	2,179,103	611,944	591,922	$ 15,267,970
System Actual $ - Capacity component of HB589 Purpa QF purchases	240,541	314,914	229,175	301,405	216,488	298,037	1,151,852	1,312,758	1,272,900	1,184,456	259,220	187,603	$ 6,969,349
System Actual $ - Capacity component of SC DERP	32	4,343	4,209	5,850	3,530	4,199	3,177	3,738	3,716	3,670	2,375	2,168	$ 41,006
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 1,276,149	$ 1,484,644	$ 1,194,514	$ 1,348,036	$ 1,321,197	$ 2,506,702	$ 6,663,862	$ 7,122,875	$ 4,366,089	$ 3,580,594	$ 1,086,905	$ 995,058	$ 32,946,626
NC Actual $ (Calc) (1)	$ 862,169	$ 1,003,029	$ 807,016	$ 910,736	$ 895,069	$ 1,698,211	$ 4,514,555	$ 4,825,522	$ 2,957,887	$ 2,425,739	$ 736,343	$ 674,120	$ 22,310,397
Billed rate (¢/kWh):	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0342	0.0327	0.0327	0.0327	
Billed $:	$ 1,773,631	$ 1,775,723	$ 1,542,370	$ 1,506,151	$ 1,561,807	$ 1,776,506	$ 1,951,359	$ 2,017,285	$ 1,886,955	$ 1,535,934	$ 1,406,799	$ 1,561,982	$ 20,296,502
(Over)/Under $:	$ (911,461)	$ (772,694)	$ (735,354)	$ (595,415)	$ (666,739)	$ (78,295)	$ 2,563,196	$ 2,808,237	$ 1,070,932	$ 889,805	$ (670,455)	$ (887,863)	$ 2,013,895
TOTAL (Over)/ Under $:	**$ 7,015,780**	**$ 1,811,363**	**$ 15,688**	**$ 1,682,813**	**$ (2,129,491)**	**$ (2,795,372)**	**$ (864,756)**	**$ (649,496)**	**$ (1,695,060)**	**$ 156,785**	**$ (119,692)**	**$ (811,539)**	**$ 1,617,020**

Note: The billed rate for September and October are pro-rated based on number of billing days in cycle on new rate schedules.

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
2.5% calculation test
Twelve Months Ended December 31, 2018
Docket E-7, Sub 1228

McGee Workpaper 10b

2018	**Jan18**	**Feb18**	**Mar18**	**Apr18**	**May18**	**June 18**	**Jul18**	**Aug18**	**Sep18**	**Oct18**	**Nov18**	**Dec18**	**12 ME**
System KWH Sales - Sch 4, Adjusted	8,703,429,931	7,459,691,118	6,449,998,012	6,590,329,093	6,591,233,338	8,009,317,385	8,486,873,480	8,267,869,991	9,507,963,860	6,345,056,567	6,681,164,890	7,500,839,324	90,593,766,989
NC Retail KWH Sales - Sch 4	5,733,819,698	5,031,181,342	4,190,094,169	4,416,566,036	4,252,750,024	5,245,688,511	5,639,360,853	5,409,821,248	6,212,763,717	4,141,211,581	4,314,713,247	4,892,732,160	59,480,702,586
NC Retail % of Sales, Adjusted (Calc)	65.88%	67.44%	64.96%	67.02%	64.52%	65.49%	66.45%	65.43%	65.34%	65.27%	64.58%	65.23%	65.66%
NC retail production plant %	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 54,851,829	$ 19,768,561	$ 11,751,953	$ 8,971,622	$ 7,588,225	$ 7,853,735	$ 25,151,873	$ 24,971,461	$ 21,908,434	$ 27,821,901	$ 26,826,328	$ 40,057,563	$ 277,523,485
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	18,300,781	2,407,886	1,331,655	1,356,382	1,684,418	1,881,586	2,920,154	3,759,304	6,703,809	4,827,502	6,105,374	13,849,586	$ 65,128,437
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	3,057,332	3,239,022	2,726,561	3,894,992	4,543,762	4,545,750	4,893,476	4,813,048	4,818,507	3,635,758	4,331,202	3,811,118	$ 48,310,528
System Actual$ - Sch 3 Fuel-related$; SC DERP	122	125	134	163	218	223	232	223	213	203	157	136	$ 2,149
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	1,692,902	2,049,413	2,053,505	2,531,173	2,424,811	2,829,385	2,716,750	2,487,659	2,471,326	2,042,872	2,089,973	1,712,356	$ 27,102,125
Total System Economic & QF$	77,902,966	27,465,007	17,863,808	16,754,332	16,241,434	17,110,679	35,682,485	36,031,695	35,902,289	38,328,236	39,353,034	59,430,759	418,066,724
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 30,897,067	$ 15,346,230	$ 7,372,650	$ 7,540,311	$ 5,735,851	$ 6,332,102	$ 23,572,626	$ 21,641,030	$ 15,422,513	$ 23,414,464	$ 20,577,089	$ 28,953,467	$ 206,805,400
Total System Economic $ without Native Load Transfers	$ 47,005,899	$ 12,118,777	$ 10,491,158	$ 9,214,021	$ 10,505,583	$ 10,778,577	$ 12,109,859	$ 14,390,665	$ 20,479,776	$ 14,913,772	$ 18,775,945	$ 30,477,292	$ 211,261,324
NC Actual $ (Calc)	$ 30,967,487	$ 8,173,497	$ 6,815,342	$ 6,174,856	$ 6,778,340	$ 7,059,410	$ 8,046,764	$ 9,416,080	$ 13,382,046	$ 9,733,733	$ 12,125,553	$ 19,880,072	$ 138,553,178
Billed rate (¢/kWh):	0.0868	0.0868	0.0868	0.0868	0.0868	0.0868	0.0868	0.0868	0.1631	0.1921	0.1922	0.1922	
Billed $:	$ 4,979,550	$ 4,369,342	$ 3,638,897	$ 3,835,577	$ 3,693,311	$ 4,555,631	$ 4,897,517	$ 4,698,172	$ 10,132,031	$ 7,954,367	$ 8,291,468	$ 9,402,231	$ 70,448,093
(Over)/ Under $:	$ 25,987,937	$ 3,804,155	$ 3,176,444	$ 2,339,278	$ 3,085,029	$ 2,503,779	$ 3,149,247	$ 4,717,908	$ 3,250,015	$ 1,779,366	$ 3,834,085	$ 10,477,841	$ 68,105,086
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ 422,948	$ 422,948	$ 211,474	$ 211,474	$ 317,211	$ 1,374,581	$ 3,172,110	$ 3,116,270	$ 630,852	$ 211,474	$ 211,474	$ 211,474	$ 10,514,290
System Actual $ - Capacity component of Purchased Power for REPS Compliance	486,469	465,590	421,064	517,448	539,749	567,326	2,279,476	2,238,065	2,451,979	1,649,703	659,013	594,902	$ 12,870,784
System Actual $ - Capacity component of HB589 Purpa QF purchases	316,410	362,951	415,622	397,922	232,512	271,686	1,225,424	1,199,461	1,251,154	924,601	242,932	159,399	$ 7,000,074
System Actual $ - Capacity component of SC DERP	57	37	64	28	13	21	78	84	72	79	19	13	$ 565
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 1,225,884	$ 1,251,526	$ 1,048,224	$ 1,126,872	$ 1,089,485	$ 2,213,614	$ 6,677,088	$ 6,553,880	$ 4,334,057	$ 2,785,857	$ 1,113,438	$ 965,788	$ 30,385,713
NC Actual $ (Calc) (1)	$ 828,210	$ 845,534	$ 708,183	$ 761,317	$ 736,059	$ 1,495,523	$ 4,511,056	$ 4,427,817	$ 2,928,099	$ 1,882,131	$ 752,241	$ 652,488	$ 20,528,657
Billed rate (¢/kWh):	0.0241	0.0241	0.0241	0.0241	0.0241	0.0241	0.0241	0.0241	0.0289	0.0353	0.0353	0.0353	
Billed $:	$ 1,383,962	$ 1,214,368	$ 1,011,356	$ 1,066,019	$ 1,026,479	$ 1,266,143	$ 1,361,163	$ 1,305,759	$ 1,795,614	$ 1,462,023	$ 1,524,125	$ 1,728,304	$ 16,145,316
(Over)/Under $:	$ (555,752)	$ (368,834)	$ (303,173)	$ (304,702)	$ (290,420)	$ 229,380	$ 3,149,893	$ 3,122,057	$ 1,132,485	$ 420,108	$ (771,884)	$ (1,075,816)	$ 4,383,341
TOTAL (Over)/ Under $:	**$ 25,432,185**	**$ 3,435,322**	**$ 2,873,271**	**$ 2,034,577**	**$ 2,794,608**	**$ 2,733,159**	**$ 6,299,140**	**$ 7,839,965**	**$ 4,382,500**	**$ 2,199,474**	**$ 3,062,201**	**$ 9,402,025**	**$ 72,488,427**

DUKE ENERGY CAROLINAS **McGee Workpaper 11**
North Carolina Annual Fuel and Fuel Related Expense
Actual Sales by Jursidication - Subject to Weather
Twelve Months Ended December 31, 2019
Docket E-7, Sub 1228
MWhs

Line #	Description	Reference	NORTH CAROLINA	SOUTH CAROLINA	Retail TOTAL COMPANY	% NC	% SC
1	Residential	Company Records	22,091,823	6,769,118	28,860,942	76.55	23.45
2	Total General Service	Company Records	24,259,901	5,688,279	29,948,180		
3	less Lighting and Traffic Signals		272,655	47,509	320,164		
4	General Service subject to weather		23,987,245	5,640,770	29,628,016	80.96	19.04
5	Industrial	Company Records	12,290,797	9,009,119	21,299,916	57.70	42.30
6	Total Retail Sales	1+2+5	58,642,521	21,466,517	80,109,038		
7	Total Retail Sales subject to weather	1+4+5	58,369,866	21,419,008	79,788,874	73.16	26.84

This does not exclude Greenwood and includes the impact of SC DERP net metering generation

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment
Twelve Months Ended December 31, 2019
Docket E-7, Sub 1228

Line #	Description	REFERENCE	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Total Residential		219,018	76.55	167,658	23.45	51,360
	General Service						
2	Total General Service		(765,439)	80.96	(619,699)	19.04	(145,740)
	Industrial						
3	Total Industrial		234,566	57.70	135,345	42.30	99,221
4	Total Retail	L1+ L2+ L3	(311,855)		(316,696)		4,841
5	Wholesale		76,245				
6	Total Company	L4 + L5	(235,610)		(316,696)		4,841

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment by Class by Month
Twelve Months Ended December 31, 2019
Docket E-7, Sub 1228

	Residential	**Commercial**	**Industrial**	
2019	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	
JAN	403,189	21,753	106,910	
FEB	133,613	(93,968)	7,903	
MAR	317,291	-	84,782	
APR	(15,943)	(3,954)	34,885	
MAY	(122,691)	(142,134)	(66,793)	
JUN	(96,008)	(206,667)	51,708	
JUL	(78,685)	(39,023)	(12,174)	
AUG	(83,867)	(44,228)	(21,152)	
SEP	(108,844)	(66,903)	(30,443)	
OCT	(294,829)	(193,846)	53,194	
NOV	71,113	16,545	25,747	
DEC	94,681	(13,014)	-	
Total	**219,018**	**(765,439)**	**234,566**	**(311,855)**

Wholesale

2019	**TOTAL MWH ADJUSTMENT**	Note:	**The Resale customers include:**
JAN	(38,538)	1	Dallas
FEB	41,582	2	Forest City
MAR	(15,191)	3	Due West
APR	5,372	4	Prosperity
MAY	(30,683)	5	Lockhart
JUN	(10,771)	6	Western Carolina University
JUL	(3,961)	7	City of Highlands
AUG	(2,012)	8	Haywood
SEP	(55,637)	9	Piedmont
OCT	16,676	10	Rutherford
NOV	95,238	11	Blue Ridge
DEC	74,172	12	
		13	
Total	**76,245**	14	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales
Twelve Months Ended December 31, 2019
Docket E-7, Sub 1228

McGee Workpaper 13
Page 1

Line	Estimation Method [1]	Rate Schedule	NC Proposed KWH [1] Adjustment	SC Proposed KWH Adjustment	Wholesale Proposed KWH Adjustment	Total Company
1	*Regression*	Residential	184,999,964	76,243,652		
2						
3		**General Service (excluding lighting):**				
4	*Customer*	General Service Small and Large	48,355,467	6,071,876		
5	*Regression*	Miscellaneous	104,327	(19,325)		
6		Total General	48,459,794	6,052,551		
7						
8		**Lighting:**				
9	*Regression*	T & T2 (GL/FL/PL/OL)2	(128,699)	739,852		
10	*Regression*	TS	16,909	96,601		
11		Total Lighting	(111,790)	836,453		
12						
13		**Industrial:**				
14	*Customer*	I - Textile	(2,509,370)	-		
15	*Customer*	I - Nontextile	65,875,298	2,958,646		
16		Total Industrial	63,365,928	2,958,646		
17						
18						
19		Total	296,713,896	86,091,302	72,243,004	455,048,203
					WP 13-2	

Notes:
[1] Two approved methods are used for estimating the growth adjustment depending on the class/schedule:
"Regression" refers to the use of Ordinary Least Squares Regression
"Customer" refers to the use of the Customer by Customer approach. See ND330 for further explanation
[2] T and T2 were combined due to North Carolina's FL & GL schedules being merged into OL & PL during the 12 month period.
rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales-Wholesale
Twelve Months Ended December 31, 2019
Docket E-7, Sub 1228

Calculation of Customer Growth Adjustment to KWH Sales - Wholesale

Line No.		Reference	
1	Total System Resale (kWh Sales)	Company Records	10,026,499,101
2	Less Intersystem Sales	Schedule 1	2,045,438,486
3	Total KWH Sales Excluding Intersystem Sales	L1 - L2	7,981,060,615
4	Residential Growth Factor	Line 8	0.9052
5	Adjustment to KWH's - Wholesale	L3 * L4 / 100	72,243,004
6	Total System Retail Residential kWh Sales	Company Records	28,860,941,635
7	2019 Proposed Adjustment KWH - Residential (NC+SC)	WP 13 1	261,243,616
8	Percent Adjustment	L7 / L6 * 100	0.9052

"RAC001": CarolinasOperating Revenue Report

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Regis Repko and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am Senior Vice President and Chief Fossil/Hydro Officer for Duke Energy Carolinas, LLC ("DEC" or the "Company").

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

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

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

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

A. Yes. I testified before this Commission in the DEP NC 2015 Fuel Hearing Docket No. E-2, Sub 1069.

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

A. The purpose of my testimony is to (1) describe DEC's Fossil/Hydro/Solar generation portfolio and changes made since the 2019 fuel and fuel-related cost recovery proceeding, as well as those expected in the near term, (2) discuss the performance of DEC's Fossil/Hydro/Solar facilities during the test period of January 1, 2019 through December 31, 2019 (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 DEC'S FOSSIL/HYDRO/SOLAR GENERATION PORTFOLIO.

A. The Company's Fossil/Hydro/Solar generation portfolio consists of approximately 14,976 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	6,764 MWs
Steam Natural Gas -	170 MWs
Hydro -	3,219 MWs
Combustion Turbines -	2,665 MWs
Combined Cycle Turbines -	2,116 MWs

Solar -	30 MWs
Combined Heat and Power	13 MWs

The coal-fired assets consist of four generating stations with a total of 13 units. These units are equipped with emissions control equipment, including selective catalytic or selective non-catalytic reduction ("SCR" or "SNCR") equipment for removing nitrogen oxides ("NO_x"), and flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"). In addition, all 13 coal-fired units are equipped with low NO_x burners. The steam natural gas unit – Lee Station ("Lee") Unit 3 – is considered to be a peaking unit.

The Company has a total of 31 simple cycle combustion turbine ("CT") units, of which 29 are considered the larger group providing approximately 2,581 MWs of capacity. These 29 units are located at Lincoln, Mill Creek, and Rockingham Stations, and are equipped with water injection systems that reduce NO_x and/or have low NO_x burner equipment in use. The Lee CT facility includes two units with a total capacity of 84 MWs equipped with fast-start ability in support of DEC's Oconee Nuclear Station. The Company has 2,116 MWs of combined cycle turbines ("CC"), comprised of the Buck CC, Dan River CC and W.S. Lee CC facilities. These facilities are equipped with technology for emissions control, including SCRs, low NO_x burners, and carbon monoxide/volatile organic compounds catalysts. The Company's hydro fleet includes two pumped storage facilities with four units each that provide a total capacity of 2,140 MWs, along with conventional hydro assets consisting of 59 units providing approximately 1,079 MWs of capacity. The 30 MWs of solar capacity are made up of 18 roof top solar sites providing 3 MWs of relative summer dependable capacity, the Mocksville solar site providing 5 MWs of relative summer dependable capacity, the Monroe solar site providing 19 MWs of relative summer dependable capacity and Woodleaf providing 2 MWs of relative summer dependable capacity.

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

A. Belews Creek Unit 1 was upgraded to allow for co-fired operation, allowing utilization of coal and natural gas. Clemson Combined Heat and Power (CHP) plant went into service in December 2019. The system will provide Clemson University steam and the system with 15 MW of capacity. DEC also entered into an agreement whereby the Company sold five hydro generating stations to Northbrook Carolina Hydro II, LLC and Northbrook Tuxedo, LLC. The facilities have a combined 18.7 MW generation capacity and consist of the Bryson Hydro Station, the Franklin Hydro Station, the Mission Hydro Station, the Tuxedo Hydro Station, and the Gaston Shoals Hydro Station. Four of the facilities are in North Carolina, and the fifth is in South Carolina.

Q. WAS THE CHANGE IN OWNERSHIP OF THE HYDROELECTRIC GENERATING FACILITIES APPROVED BY THIS COMMISSION?

A. Yes. The Hydroelectric Generating Facilities sale was approved in Docket Nos. E-7, Sub 1181, SP-12478, Sub 0, and SP-12479, Sub 0.

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

A. The primary objective of DEC's Fossil/Hydro/Solar generation department is to provide safe, reliable and cost-effective electricity to DEC's customers. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with procedures, guidelines, and a standard operating model.

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

Q. WHAT IS HEAT RATE?

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy.

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

A. Over the test period, the average heat rate for DEC's coal fleet was 9,599 Btu/kWh. DEC's Rogers Energy Complex ("Cliffside"), Belews Creek Steam Station ("Belews Creek"), and Marshall Steam Station ("Marshall") typically rank as some of the most efficient coal-fired generating stations in the nation, with heat rates of 9,433, Btu/kWh, 9,366 Btu/kWh, and 9,687 Btu/kWh, respectively. For the test period, the Marshall units provided 35% of coal-fired generation for DEC, with the Belews Creek units providing 32% and Cliffside providing 29%.

Q. HOW MUCH GENERATION DID EACH TYPE OF FOSSIL/HYDRO/SOLAR GENERATING FACILITY PROVIDE FOR THE TEST PERIOD AND HOW DOES DEC UTILIZE EACH TYPE OF GENERATING FACILITY TO SERVE CUSTOMERS?

A. The Company's system generation totaled 100.2 million MW hours ("MWhs") for the test period. The Fossil/Hydro/Solar fleet provided 39.2 million MWhs, or approximately 39% of the total generation. As a percentage of the total generation, 21% was produced from coal-fired stations and approximately 14% from CC operations, 1% from CTs, 2% from hydro facilities, and 0.14% from solar.

The Company's portfolio includes a diverse mix of units that, along with additional nuclear capacity, allows DEC to meet the dynamics of customer load requirements in a cost-effective manner. Additionally, DEC has utilized the Joint Dispatch Agreement, which allows generating resources for DEC and DEP to be dispatched as a single system to enhance dispatching by allowing DEC customers to benefit from the lowest cost resources available. The cost and operational characteristics of each unit generally determine the type of customer load situation (*e.g.*, base and peak load requirements) that a unit would be called upon, or dispatched, to support.

Q. HOW DID DEC COST EFFECTIVELY DISPATCH ITS DIVERSE MIX OF GENERATING UNITS DURING THE TEST PERIOD?

A. The Company, like other utilities across the U.S., has experienced a change in the dispatch order for each type of generating facility due to continued favorable economics resulting from low pricing of natural gas. Further, the addition of new CC units within the Carolinas' portfolio in recent years has provided DEC 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.

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

A. The Company's generating units operated efficiently and reliably during the test period. The following 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[1] hours); a low EFOR represents fewer unplanned outages 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 operation results, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Availability Brochure ("NERC Brochure") representing the period 2014 through 2018, and is categorized by generator type. The NERC data reported represents an average of comparable units based on capacity rating. The data in the chart reflects DEC results compared to the NERC five-year averages.

Generator Type	Measure	Review Period	2014-2018	Nbr of Units
		DEC Operational Results	NERC Average	
Coal-Fired Test Period	EAF	76.9%	77.3%	712
	NCF	36.2%	54.8%	
	EFOR	7.4%	9.3%	
Coal-Fired Summer Peak	EAF	92.6%	n/a	n/a
Total CC Average	EAF	78.0%	84.9%	333
	NCF	71.3%	53.6%	
	EFOR	0.37%	5.1%	
Total CT Average	EAF	83.2%	87.5%	750
	SR	100.0%	98.3%	
Hydro	EAF	83.4%	80.2%	1,063

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

A. In general, planned maintenance outages for all fossil and larger hydro units are scheduled for the spring and fall to maximize unit availability during periods of

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

peak demand. Most of these units had at least one small planned outage during this test period to inspect and maintain plant equipment.

W.S. Lee Station conducted an outage in the Fall 2019. The primary purpose for the W.S. Lee Station outage was for Transmission to perform Bus Tie Breaker and 100kv Bus Junction Breakers Upgrades.

In the Spring 2019, Dan River CC conducted major gas turbine overhauls, as well as steam turbine valve and generator inspections. Marshall Unit 2 completed an outage in the Spring 2019. The primary purpose of this outage was to conduct stack repairs and install fly ash piping replacement. Marshall Unit 3 completed an outage in the Spring 2019. The primary purpose of this outage was to perform air preheater maintenance. Marshall Unit 4 completed an outage in the Spring 2019. The primary purpose of this outage was to conduct boiler inspections and stack inspections. W.S. Lee CC completed an outage in Spring 2019. The primary purpose of the outage was to perform inspections and balance of plant maintenance. Buck CC completed an outage in Spring 2019. The primary purpose of the outage was to perform a hot gas path inspection on the gas turbines. Lincoln CT Units 11-16 completed an outage in Spring 2019 to upgrade the turbine control systems.

In Fall 2019, Belews Creek Unit 1 preformed a boiler outage. The primary purpose of the outage was to replace the horizonal reheat section of the boiler, burner installation for the natural gas co-fire conversion, and precipitator upgrades. Belews Creek Unit 2 was also in an outage to perform work on common service water pipe replacement between units, continuous emission monitoring system (CEMS) upgrade, main battery replacement, and control system power supply upgrade. Marshall Unit 2 completed an outage in Fall 2019. The primary purpose of this outage was to perform FGD inspections, repair absorber agitators, and replace check valves. Marshall Unit 1 also had an outage in the Fall 2019 to replace the generator and transformer protective relays and air preheater baskets. Cliffside Unit 5 performed work on ammonia tank inspections, catalysts replacement, and turbine valve work in the Fall 2019.

Q. HOW DOES DEC 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 DEC currently operates on the coal-fired units uses ammonia or urea for NO_x removal. The SNCR technology employed at Allen Station and Marshall Units 1, 2 and 4 injects urea into the boiler for NO_x removal. All DEC coal units have wet scrubbers installed that use crushed limestone for SO_2 removal. Cliffside Unit 6 has a state-of-the-art SO_2 reduction system that couples a wet scrubber (*e.g.*, limestone) and dry scrubber (*e.g.*, quicklime). SCR equipment is also an integral part of the design of the Buck, Dan River and Lee CC Stations in which aqueous ammonia 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 the operation of the unit. The Company will continue to leverage new technologies and chemicals to meet both present and future state and federal emission requirements including the Mercury and Air Toxics Standards ("MATS") rule. MATS chemicals that DEC uses when required to reduce emissions include, but may not be limited to, activated carbon, mercury oxidation chemicals, and mercury re-emission prevention chemicals. Company witness McGee provides the cost information for DEC'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-7, SUB 1228

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin Y. Houston 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 Supply for Duke Energy Carolinas, LLC ("DEC" or the "Company") and Duke Energy Progress, LLC ("DEP").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEC?

A. I am responsible for nuclear fuel procurement for the nuclear units owned and operated by DEC and DEP.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Florida with a Bachelor of Science degree in Nuclear Engineering, and from North Carolina State University with a Master's degree in Nuclear Engineering. I began my career with the Company in 1992 as an engineer and worked in Duke Energy's nuclear design group where I performed nuclear physics roles. I assumed my current role having commercial responsibility for purchasing uranium, conversion services, enrichment services, and fuel fabrication services in 2012.

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. I became a registered professional engineer in the state of North Carolina in 2003.

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

A. Yes. I filed testimony in the DEC fuel and fuel-related cost recovery proceedings in Docket E-7, Sub 1190.

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

A. The purpose of my testimony is to (1) provide information regarding DEC's nuclear fuel purchasing practices, (2) provide costs for the January 1, 2019 through December 31, 2019 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2020 through August 31, 2021 billing period ("billing period").

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

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Houston Exhibit 1, which is a Graphical Representation of the Nuclear Fuel Cycle, and Houston 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 Houston 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 DEC'S NUCLEAR FUEL PROCUREMENT PRACTICES.

A. As set forth in Houston Exhibit 2, DEC'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. DEC 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, DEC'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 DEC's exposure to price volatility. Diversifying fuel suppliers reduces DEC's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Q. PLEASE DESCRIBE DEC'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 DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets. DEC 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, DEC entered into several long-term contracts during the test period.

DEC's portfolio of diversified contract pricing yielded an average unit cost of $45.00 per pound for uranium concentrates during the test period, representing no appreciable change from the prior test period.

A majority of DEC'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 DEC's exposure to price volatility. The average unit cost of DEC's purchases of enrichment services during the test period decreased 3% to $115.10 per Separative Work Unit.

Delivered costs for fabrication and conversion services have a limited impact on the overall fuel expense rate given that the dollar amounts for these purchases represent a substantially smaller percentage – 15% and 4%, respectively, for the fuel batches recently loaded into DEC's reactors – of DEC's total direct fuel cost relative to uranium concentrates or enrichment, which are 43% and 38%, respectively.

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

A. Prices for uranium concentrate remain relatively low with the continued overhang of excess material in the market. Production levels have begun to decrease and industry consultants, believe market prices will need to increase from current levels in order to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements.

Market prices for enrichment services have begun to rebound as demand has returned to the market 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. For conversion services, market prices have continued to increase during the test period.

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

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

The average fuel expense is expected to increase from 0.5978 cents per kWh incurred in the test period, to approximately 0.6040 cents per kWh in the billing period.

Q. WHAT STEPS IS DEC 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 Houston Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEC 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, DEC'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 DEC'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 DEC'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.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

In the Matter of	)	
Application of Duke Energy Carolinas, 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 CAROLINAS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

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

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR

PROCEEDING?

A. Yes. I testified in support of DEP's 2019 fuel and fuel-related cost recovery application in Docket No. E-2, Sub 1204 and 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 DEC's fossil fuel purchasing practices, provide actual fossil fuel costs for the period January 1, 2019 through December 31, 2019 ("test period") versus the period January 1, 2018 through December 31, 2018 ("prior test period"), and describe changes projected for the billing period of September 1, 2020 through August, 31 2021 ("billing period").

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

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Phipps Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Phipps Exhibit 2, which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases for the test period and prior test period, and Phipps Confidential Exhibit 3, which summarizes the annual 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. Lastly, Phipps Confidential Exhibit 4, summarizes the findings of the

Company's review of its forecasting and hedging programs as ordered by the Commission in its *Order Approving Fuel Charge Adjustment* in Docket No. E-7, Sub 1190 ("2019 Fuel Order").

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

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

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

A. Both DEC and DEP 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 factors that include, but are not limited to, the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

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

A. The Company's average delivered cost of coal per ton for the test period was $82.11 per ton, compared to $78.71 per ton in the prior test period, representing an increase of approximately 4%. This includes an average transportation cost of $28.33 per ton in the test period, compared to $29.58 per ton in the prior test period, representing a decrease of approximately 4%. The Company's average price of gas purchased for the test period was $3.40 per Million British Thermal Units ("MMBtu"), compared to $3.84 per MMBtu in the prior test period, representing a decrease of approximately 11%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEC's coal burn for the test period was 8.1 million tons, compared to a coal burn of 8.7 million tons in the prior test period, representing a decrease of 7%. The Company's natural gas burn for the test period was 123.9 MMBtu, compared to a gas burn of 128.8 MMBtu in the prior test period, representing a decrease of approximately 4%. The net decrease in DEC's overall natural gas burn was primarily driven by gas to coal switching as a result of the new coal rail transportation rate that went into effect March 1, 2019.

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

A. Coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in the short term, such dynamics are influenced primarily by seasonal weather demand and overall storage inventory balances. In addition, there continues to be growth in the natural gas pipeline infrastructure needed to serve increased market demand. However, pipeline infrastructure permitting and regulatory process approval efforts are taking longer due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing.

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

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

A. DEC's current coal burn projection for the billing period is 5.4 million tons, compared to 8.1 million tons consumed during the test period. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $73.90 per ton for the billing period compared to $82.11

per ton in the test period. This includes an average projected total transportation cost of $28.46 per ton for the billing period, compared to $28.33 per ton in the test period. The projected cost is due, in part, to the negotiated rail transportation contracts which went into effect in March 2019. This projected delivered cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEC is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

DEC's current natural gas burn projection for the billing period is approximately 201.9 MMBtu, which is an increase from the 123.9 MMBtu consumed during the test period. The net increase in DEC's overall natural gas burn projections for the billing period versus the test period is driven by the inclusion of natural gas generation at Belews Creek, and Marshall Units 3 & 4 as a result of the dual fuel conversions being commercially available over the course of the billing period, combined with increased generation output from Lincoln CT. The current average forward Henry Hub price for the billing period is $2.44 per MMBtu, compared to $2.63 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

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

A. The Company continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost effective manner. With respect to coal procurement, the Company's procurement strategy includes: (1) having an appropriate mix of term contract and spot purchases for coal; (2) staggering coal contract expirations in order to limit exposure to forward market price changes; and (3) diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels.

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

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

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

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

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

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

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

A. Yes, it does.

Duke Energy 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, projected renewable capacity, and wholesale energy imports and exports.
- Station and system inventory targets are developed to provide reliability, insulation from short-term market volatility, and sensitivity to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to determine additional needs.
- All qualified suppliers are invited to participate in proposals to satisfy additional or contract needs.
- Spot market solicitations are conducted on an on-going basis to supplement contract purchases.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, quality, transportation, reliability and flexibility.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on certified scale weights and coal quality analysis meeting ASTM standards as established by ASTM International.

Gas

- Near and long-term natural gas consumption is forecasted based on inputs such as load projections, commodity and emission prices, projected renewable capacity, and fleet maintenance and availability schedules.
- Physical procurement targets are developed to procure a cost effective and reliable natural gas supply.
- Over time, short-term and long-term Requests for Proposals and market solicitations are conducted with potential suppliers to procure the cost competitive, secure, and reliable natural gas supply, firm transportation, and storage capacity needed to meet forecasted gas usage.
- Short-term and spot purchases are conducted on an on-going basis to supplement term natural gas supply.
- On a continuous basis, existing purchases are compared against forecasted gas usage to ascertain additional needs.
- Natural gas transportation for the generation fleet is obtained through a mix of long term firm transportation agreements, and shorter term pipeline capacity purchases.
- A targeted percentage of the natural gas fuel price exposure is managed via a rolling 36-month structured financial natural gas hedging program.
- Through the Asset Management and Delivered Supply Agreement between Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC implemented on January 1, 2103, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for the combined Carolinas gas fleet.

Fuel Oil

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

DUKE ENERGY CAROLINAS
Summary of Coal Purchases
Twelve Months Ended December 31, 2019 & 2018
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
1	January 2019	467,830	111,867	579,698
2	February	555,624	64,276	619,900
3	March	551,679	112,937	664,616
4	April	476,648	227,914	704,562
5	May	549,400	152,538	701,938
6	June	647,313	140,296	787,609
7	July	692,046	77,088	769,134
8	August	732,253	115,963	848,217
9	September	469,275	204,304	673,579
10	October	471,409	231,850	703,259
11	November	397,228	239,441	636,669
12	December	560,959	202,536	763,494
13	**Total** (Sum L1:L12)	**6,571,664**	**1,881,010**	**8,452,675**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
14	January 2018	453,756	60,390	514,146
15	February	770,299	0	770,299
16	March	818,185	48,963	867,148
17	April	728,025	13,269	741,294
18	May	712,466	11,116	723,582
19	June	683,250	37,208	720,458
20	July	717,234	149,366	866,600
21	August	678,523	221,949	900,470
22	September	564,680	218,860	783,537
23	October	387,121	95,651	482,771
24	November	349,180	53,825	403,003
25	December	483,536	96,525	580,061
26	**Total** (Sum L14:L25)	**7,346,255**	**1,007,122**	**8,353,369**

DUKE ENERGY CAROLINAS
Summary of Gas Purchases
Twelve Months Ended December 31, 2019 & 2018
MBTUs

Line No.	Month	MBTUs
1	January 2019	11,540,233
2	February	11,895,973
3	March	8,829,116
4	April	7,309,473
5	May	12,448,810
6	June	10,195,827
7	July	12,505,061
8	August	12,104,186
9	September	12,459,839
10	October	8,409,940
11	November	5,772,711
12	December	10,423,250
13	**Total** (Sum L1:L12)	**123,894,419**

Line No.	Month	MBTUs
14	January 2018	6,638,156
15	February	6,512,143
16	March	10,050,310
17	April	10,537,626
18	May	10,067,211
19	June	12,715,364
20	July	15,647,875
21	August	12,892,804
22	September	12,377,677
23	October	10,303,322
24	November	11,867,520
25	December	9,183,559
26	**Total** (Sum L14:L25)	**128,793,567**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

In the Matter of	)
Application of Duke Energy Carolinas, 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

FEBRUARY 25, 2020

Purpose of Document:

In its *Order Approving Fuel Charge Adjustment* ("2019 Fuel Order") in Docket No. E-7, Sub 1190, the North Carolina Utilities Commission ("NCUC") directed the Company to "evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs and report the results of that evaluation in the Company's next fuel proceeding". This document summarizes the Company's review of its method of fuel forecasting and its natural gas physical hedging programs, consistent with the Commission's 2019 Fuel Order. The document includes the following sections: 1) Overview of Company's Method of Forecasting; 2) Review of Company Method of Forecasting and Historic Natural Gas Price Fluctuations; and 3) Review of Company's Physical Hedging Programs.

Section 1: Overview of Company's Method of Forecasting:

To prepare its fuel cost projections for the applicable billing period, the Company employs a rigorous process that utilizes a production cost model called GenTrader. As part of its forecasting process, the Company updates the GenTrader production cost model with all the needed inputs, which include, but are not limited to, the following: 1) all generation unit minimum and maximum capacity ratings; 2) ramp rates; 3)heat rates; 4) VOM rates; 5) planned maintenance outage schedules; 6) forced outage rates; 7) purchased power agreements for capacity and energy; 8) solar forecasts; 9) fuel and emission prices; and, 10) system load forecasts. The specific forecast that is used to establish fuel costs and rates in the applicable regulatory filings is referred to as the Mid-Term Fuel and Operations Forecast ("FOF"). The FOF is officially produced once a quarter for a forward 5-year period. The Company also produces a fuel burn forecast each month throughout the year based on input updates including fuel prices.

With respect to the natural gas prices used in the FOF, the Company's fuel forecasting method utilizes known observable market prices from market source providers. For example, if the Company is producing its October Fall 2019 FOF, it will use the market prices for the applicable forward periods that are observable as of a specific Close of Business date. Specifically, the underlying natural gas commodity prices used for the billing period forecast in the FOF include: market observed forward curves for the NYMEX Henry Hub futures and the applicable physical locational basis for locations such as Transco Zone 4 and 5. The Company sources its forward market price curves from Morningstar, which is an established industry service provider that provides prices for natural gas and other commodities each business day. The Company also incorporates locational basis prices such as Transco Zone 5 that are observed through Request for Proposals ("RFPs"). In addition, as part of developing the total natural gas consumption costs, the Company incorporates fixed cost for: 1) firm interstate transportation agreements; 2) LDC redelivery transportation agreements; and 3) storage agreements into the final total natural gas fuel cost projection.

Once the FOF is finalized and published, it is utilized by various internal groups including the rates and regulatory group for purposes of establishing rate projections included in the applicable regulatory fuel cost recovery proceedings.

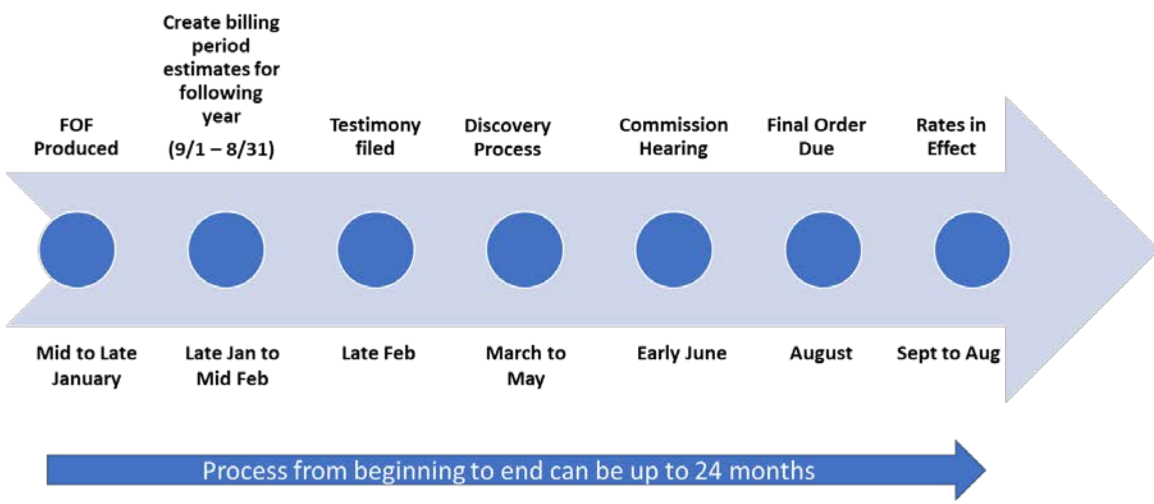
Section 2: Review of Company Method of Forecasting and Historic Natural Gas Price Fluctuations:

The Company performed a review of its forecasting method and historical natural gas price fluctuations to determine if adjustments would be warranted to mitigate the risk of significant under recoveries. The natural gas and commodity markets are dynamic and constantly changing based on market conditions. Given this reality, there will inevitably be natural price variances when comparing forecasted prices with actual prices that occurred during the billing periods.   The degree of price fluctuations that can occur over time will depend on supply and demand fundamentals, which are driven by weather trends, fuel price competition with other fuels, and other dynamic market factors.

As further background, it is also helpful to understand the regulatory timeline and specifically the amount of time that elapses between the date of production of the FOF and the point at time at which the resulting rates take effect. Diagram A below illustrates the time and key activities that are part of the regulatory process, which includes the following primary components:

- Preparation of the applicable FOF for the billing period;
- Preparation of testimony, exhibits and filings to be made to the Commission as part of the applicable fuel proceeding;
- Allotted time for the Commission, staff and intervenors to perform necessary reviews and discovery;
- Commission hearing, post hearing process and issuance of final order;

Diagram A
Timeline to Produce Fuel Cost Estimates and Bill Customers for Billing Period From September to August



As illustrated in Diagram A, the timeline from the production of FOF to the end of the billing period can be up to 24 months. Given this time frame, it is simply inevitable that natural gas prices and other inputs to the forecast will change due to changes in fundamental market conditions and other unpredictable events.

Diagrams B, C, D and E are reviewed in detail below for various periods and illustrate changes, higher or lower, that occur to natural gas prices over time, from the observed natural gas prices that existed at the time of the applicable FOF. The plotted natural gas prices in these diagrams represent observable monthly Henry Hub and Transco Zone 5 prices that were used in the applicable FOF for the outlined billing periods. The estimated monthly prices (dashed lines) on the graphs represent actual forward prices on last trading day of the month going into the applicable month during the billing period.

Diagram B illustrates the billing period of September 2015 through August 2016 when actual market prices through the billing period declined from the market prices that were observed and used in the FOF when it was developed. The observed natural gas prices used for the January 2015 FOF were current as of January 9, 2015. As outlined on Diagram B, given the cumulative effect of supply and demand factors that occurred over the summer of 2015 and the very mild winter of 2015 and 2016, actual market prices declined over time to below the market prices that existed at the time the January 2015 FOF was developed. Specifically, at the end of the 2015/2016 winter withdrawal season on April 1, 2016, US storage balances were well above typical balances at approximately 2,480 BCF versus a prior year actual of 1,472 BCF and a 5-year average of 1,606 BCF. Given the mild winter and resulting lower demand, natural gas daily spot prices eventually declined to below $2 dollar/MMBtu for a period during the first half of 2016. In summary, Diagram B provides an example where market factors occurring after the relevant FOF diverged from forecasted market conditions, causing actual prices to decrease substantially relative to forecasted prices.

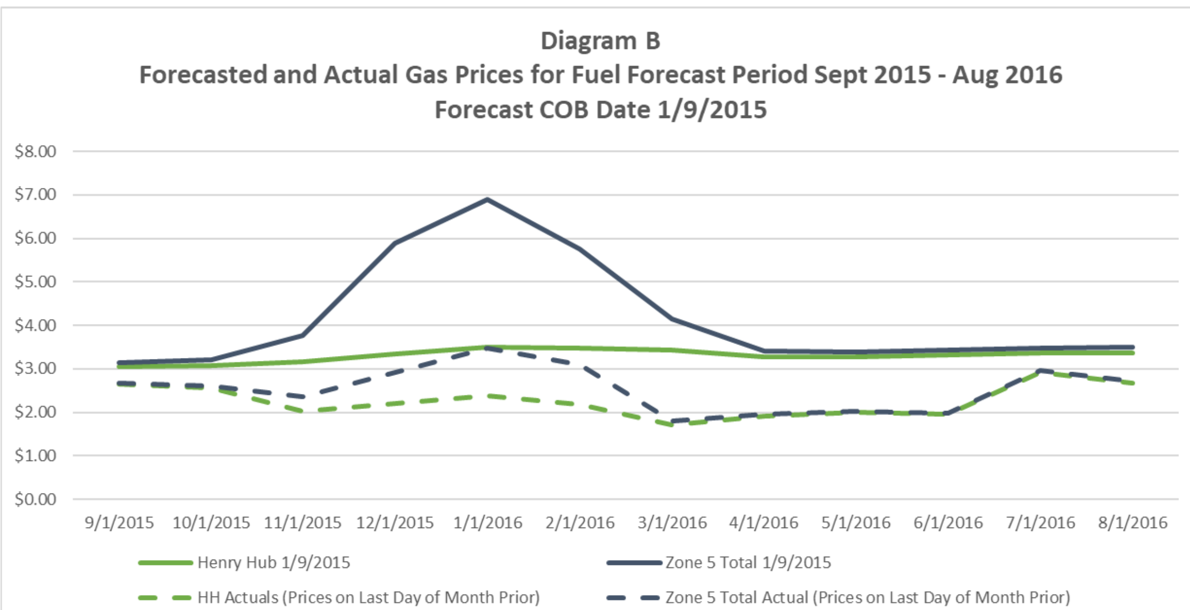
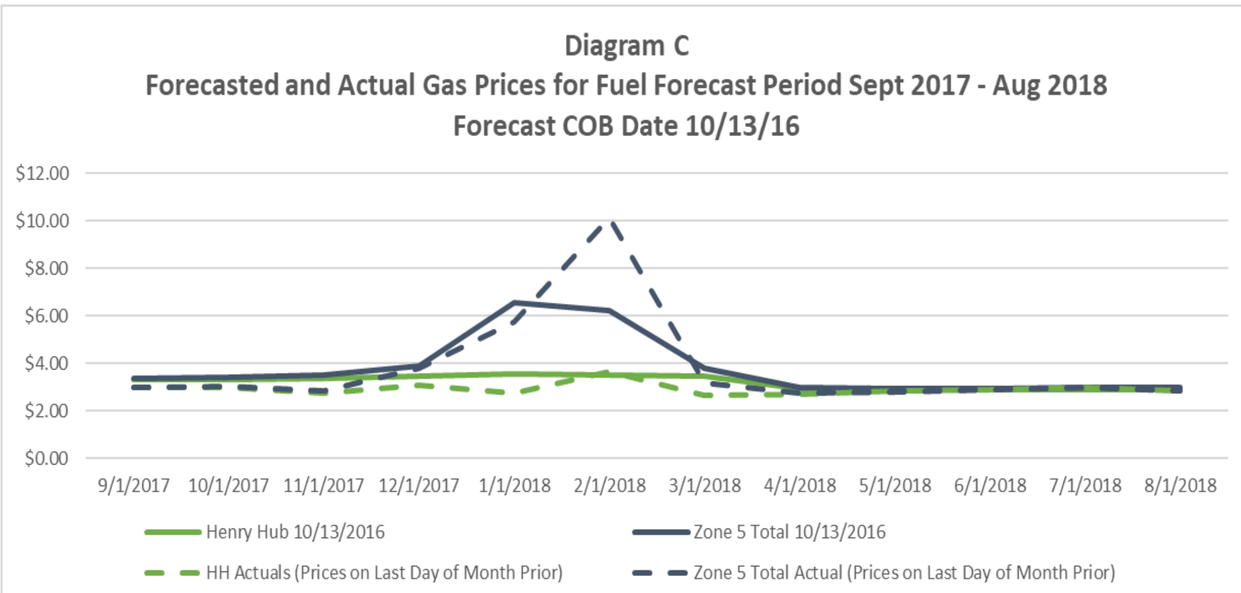
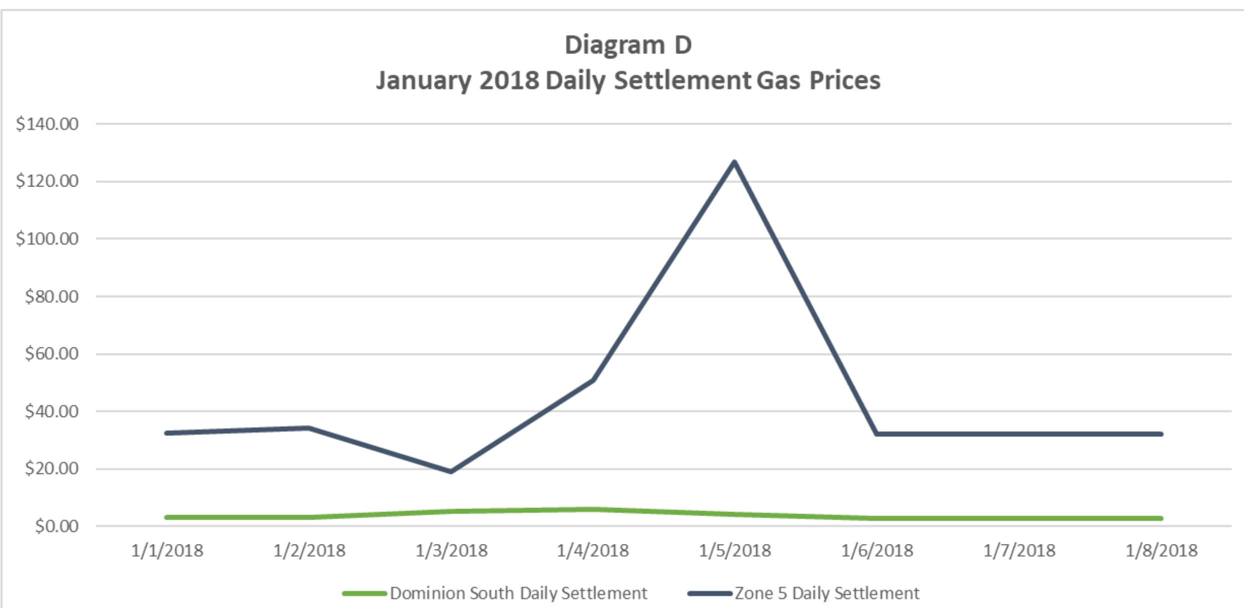


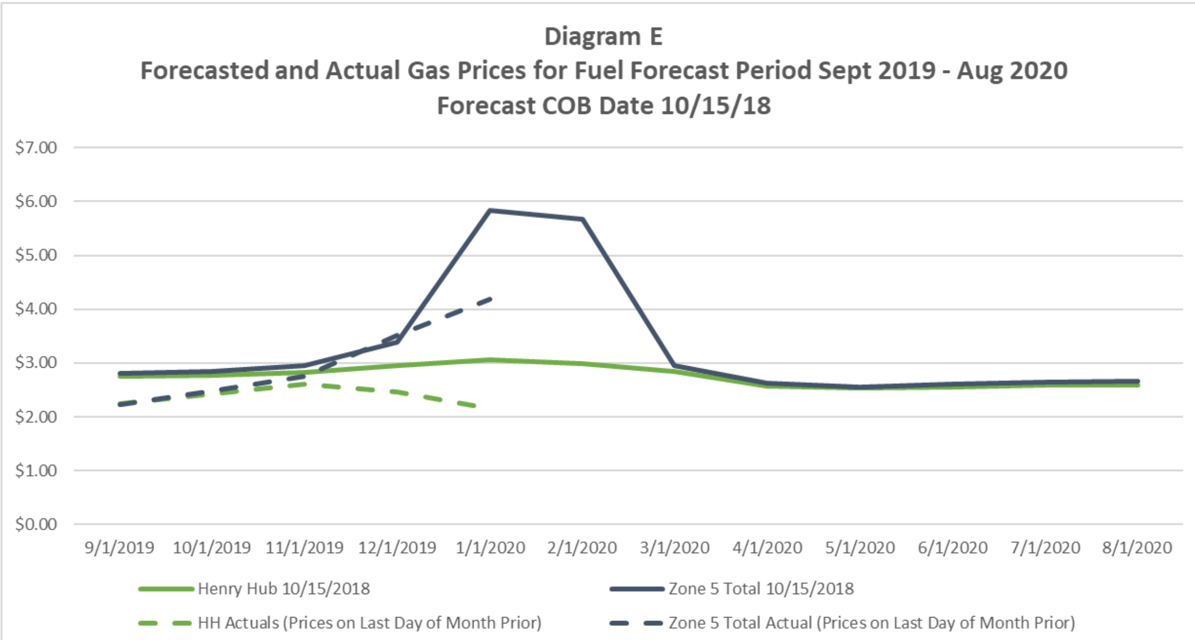
Diagram C and D provides another example from the billing period of September 2017 through August 2018, when actual monthly and daily Transco Zone 5 basis market prices spiked during the billing period to levels well above where observed prices were at the time the FOF was developed. The observed natural gas prices used for the October 2016 FOF were current as of October 13, 2016. As outlined on Diagram C, natural gas market prices were relatively in-line with forecasted prices until the period of late December 2017 and January 2018, when a historic, extended cold weather event occurred. This resulted in very high US gas demand and a spike in monthly and daily prices for the month of January 2018. This event also impacted natural gas prices in subsequent forward months as the market responded to real-time changes in the supply and demand balance for the rest of the winter, as well as the balance of the forward billing period. For example, the end of winter storage balances as of March 30, 2018 was approximately 1,354 BCF versus prior year actuals of 2,051 BCF on March 31, 2017, and 2,478 BCF on April 1, 2016. Diagram D illustrates the historic daily spot prices for Transco Zone 5, which traded over $125/MMBtu/day during the first week of January 2018. Diagram D also illustrates the differences between Dominion South and Transco Zone 5. Dominion South will be a pricing point that the Company will have direct access to with the in-service date of the Atlantic Coast Pipeline ("ACP"). The impact of ACP on the Company's physical procurement activities is discussed further in the Physical Hedging Approach section.

Once again, in summary, Diagrams C and D provide example where actual market conditions caused actual prices to diverge substantially from forecasted prices.





Lastly, Diagram E illustrates the billing period of September 2019 through August 2020 when actual market prices through the billing period declined from the market prices that were observed and used in the FOF when it was developed. The observed natural gas prices used for the October 2018 FOF were current as of October 15, 2018. As summarized on Diagram E, continued growth in US natural production to record levels throughout 2019 and a mild winter thus far through January 2020, have resulted in forward month natural gas prices falling to below $2/MMBtu.



Based on the information presented in Diagrams, A, B, C, D and E, the Company has the following observations with respect to forecasting natural gas prices:

- The observed natural gas market prices utilized for the applicable FOF are the market forward Henry Hub prices and observed locational basis that are observed in the market at the time the FOF is prepared and represents the best estimate of forecasted prices at that time;
- Mild weather or an extreme winter weather and corresponding impacts to the balance of supply and demand were a significant driver of differences in the actual market natural gas prices from those utilized in the applicable forecast;
- Weather trends over a season or short-term extreme weather events and their corresponding impacts to the balance of supply and demand, are not known and cannot be fully predicted nor forecasted without introducing significant speculation into the forecasting process;
- Given the time lag between the forecast and the end of the applicable billing period, numerous changes will occur between the actual outcomes versus the inputs that existed at the time of the FOF. Only with the benefit of hindsight could inputs such as actual weather events, prices, and system cost impacts be known.

In any review period, the Company will experience some level of over- or under-recoveries of costs from forecasted billing rates due to changes in various factors including, but not limited to, prices, weather, actual load and unit performance. Without the benefit of hindsight, the extreme and historic weather events and their impacts to pricing and associated customer costs that occurred during weather events in January 2014, which included the Polar Vortex and repeated extreme cold weather, and in late December 2017 and January 2018, could not have been forecasted or predicted by the Company many months in advance during development of the applicable FOF. In fact, the potential for these historic weather events was only known in the few weeks or days immediately prior to the events. Therefore, the Company believes inserting historical high market price events or other speculative forecasting assumptions into the Company's current forecasting processes to potentially mitigate large under-recoveries would arbitrarily increase costs billed to customers above those forecasted using current practices and could have the effect of leading to more consistent over-recoveries over the long-term.

The Company believes its current method of developing fuel and cost projections is reasonable. The current process utilizes all known information, including observed market natural gas prices that exist at the time the applicable FOF is developed and produced. The Company believes inserting speculation into the forecasting process to capture uncertain and unknown weather events, and potential price and system cost impacts to mitigate the risk of significant under-recoveries is not a reasonable business practice and would not provide benefits to the customers.

<u>Section 3: Review of Company's Hedging Approach:</u>

<u>3.A: Company's Physical Hedging Approach</u>

The Company and Public Staff discussed the Company's physical hedging approach after the Polar Vortex of 2014 and subsequent extreme weather and price events. Following this discussion, the Company did adjust its Physical Hedging approach to account for higher than forecasted Combined Cycle ("CC") usage. At that time, the Company and Public Staff agreed to continue to evaluate the winter gas procurement over time prior to the in-service date of ACP due to the potential for price fluctuations during extreme weather events.

[redacted]

[redacted]

[redacted]

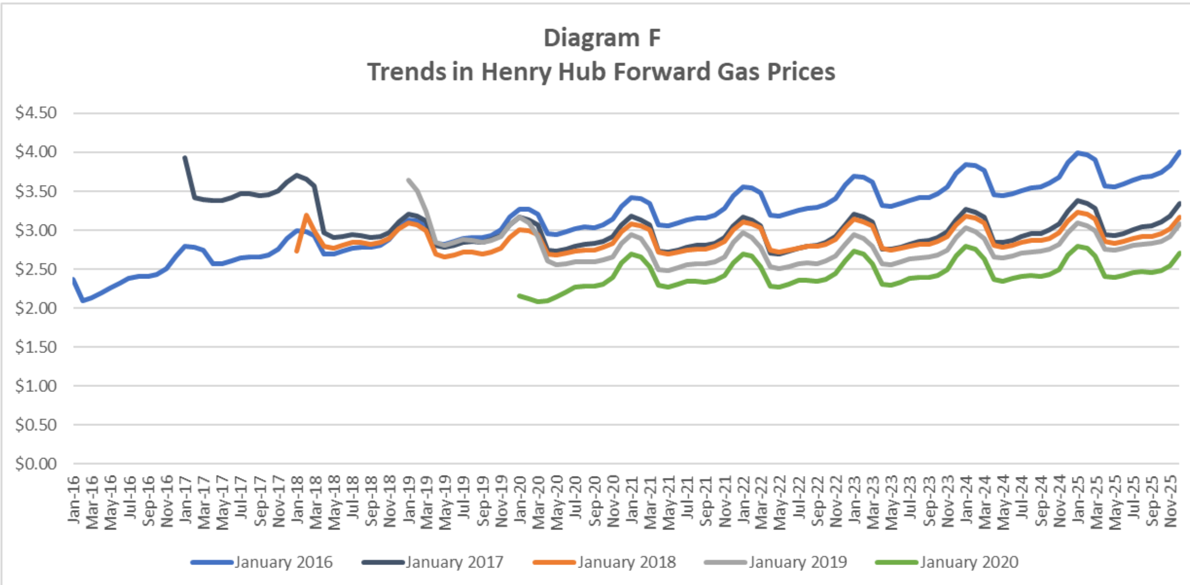
[redacted]

In addition to the procurement adjustments summarized above, the Company incorporated additional statistical price stress tests after 2014 to assess the impact of higher or lower natural gas price scenarios on forecasted burns. In addition, the Company recently put into production a production cost modeling tool with stochastic analysis capabilities. In short, the stochastic tool uses historical weather to simulate iterations of future weather. For each of these iterations, system load and commodity prices (gas, coal, oil and power) are all calculated in a correlated manner using historical correlations with each other and with weather. For example, if in a simulated iteration, winter is particularly cold, then that iteration would have higher load and corresponding higher gas and power prices which resembles historical data. It is noteworthy that the average of all simulated commodity prices matches the forward curves. The model also simulates plant outages using historical outage data. The resulting forecasts of this stochastic production cost model gives the Company not only expected fuel burns, but also the range of fuel burns and probability associated with each range. Stochastic model development has been an effort over the last couple of years and was put into production in late 2019. The Company is in the process of incorporating these probabilistic outputs into flexible user tools that can be used by the various teams including fuel procurement to review a range of probable outcomes, including a range of potential costs at different probabilities which can be part of fuel evaluations and incorporated into physical procurement and financial hedging targets and decisions.

With respect to future physical procurement activities, the Commission is aware the Company has agreements that provide for the construction and additional firm transportation with ACP and associated Supply Header. The in-service date of the additional firm transportation on ACP is contingent on the completion of construction of ACP and Supply Header Project on Dominion. ACP's current in service target date is in 2022. [redacted] This will provide benefits to the customers as ACP will provide greater fuel cost certainty and further mitigate the risk to significant under-recoveries for customers.

3.B. Company's Financial Hedging Approach

Lastly, the Company continues to utilize a structured, non-speculative approach to managing fuel cost risk by layering in financial hedging transactions over time consistent with the Company's approved hedging program. The volumes hedged over time for natural gas represent a portion of the Company's forecasted natural gas burns, with higher hedging target ranges in the near term and lower hedging target ranges in the outer period. The Company's hedging program continues to be an important part of prudent fuel cost management, as the Company's exposure to natural gas cost fluctuations continues to increase with its growing gas generation portfolio. In late 2015, the Company changed its financial hedging activities from a 2-year rolling forward time to a 3-year rolling forward time. As outlined in Diagram F below, the current forward market prices have declined over time and are currently at or near historic lows for the forward 5-year period. With the Company's growing natural gas usage, the Company believes extending the hedging activity to years 4 and 5 is a reasonable approach to mitigating price risks for its customers. [redacted]



The Company reviewed its current physical hedging approach and believes it is reasonable. Further modification from the current practices would not mitigate the risk of significant under-recoveries. As outlined in the forecasting method review section, without significant speculation and only with the benefit of hindsight could the Company know when, at what price and how much additional physical fixed priced monthly or daily Transco Zone 5 delivered gas to purchase for its generation fleet. Further adjusting the physical hedging activities to procure additional fixed priced gas based on the Company speculating on the timing and significance of weather events, price levels, and system events is not a reasonable approach and could have the effect of leading to more consistent over-recoveries over the long-term. With respect to financial hedging, the Company would recommend that extending current activities for a lower percentage in rolling years 4 and 5 is a reasonable approach to further mitigating costs risks for customers given the continued growth in gas usage.

Summary:

In summary, the Company has reviewed both its fuel forecasting and physical hedging methodology. The Company considers its fuel forecasting processes and fuel procurement approach to be reasonable for establishing fuel costs and rates for customers and making fuel procurement decisions. The Company believes introducing historical high market price events or other speculative forecasting assumptions to mitigate large under-recoveries is not reasonable and could result in more consistent over-recoveries of fuel costs over time. As noted, the Company continues to refine and add modeling capabilities that will provide the Company with additional information to help with analyzing fuel forecasts and needed procurement activities, and associated ranges of potential costs. Lastly, the Company recommends extending current financial hedging activities for a lower percentage in rolling years 4 and 5 is a reasonable approach to further mitigate cost risks for customers given the continued growth in gas usage.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven D. Capps and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy") with direct executive accountability for Duke Energy's South Carolina nuclear plants, including Duke Energy Carolinas, LLC's ("DEC" or the "Company") Catawba Nuclear Station ("Catawba") in York County, South Carolina, the Oconee Nuclear Station ("Oconee") in Oconee County, South Carolina, and Duke Energy Progress, LLC's ("DEP") Robinson Nuclear Plant, located in Darlington County, South Carolina.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a B.S. in Mechanical Engineering from Clemson University and have had over 32 years of experience in the nuclear field in various roles with increasing responsibilities. I joined Duke Energy in 1987 as a field engineer at Oconee. During my time at Oconee, I served in a variety of leadership positions at the station, including Senior Reactor Operator, Shift Technical Advisor, and Mechanical and Civil Engineering Manager. In 2008, I transitioned to McGuire as the Engineering Manager. I later became plant manager and was named Vice President of McGuire in 2012. In December 2017, I was named Senior Vice President of Nuclear Corporate for Duke with direct executive accountability for Duke Energy's nuclear corporate functions, including nuclear corporate engineering, nuclear major projects, corporate governance and operation support and organizational effectiveness. I assumed my current role in October 2018.

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

A. Yes. I provided testimony and appeared before the Commission in DEC's fuel and fuel related cost recovery proceeding in Docket No. E-7, Sub 1163 and provided testimony in DEC's fuel and fuel related cost recovery proceeding in Docket No. E-7, Sub 1190.

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

A. The purpose of my testimony is to describe and discuss the performance of DEC's nuclear fleet during the period of January 1, 2019 through December 31, 2019 ("test period"). I provide information about refueling outages completed during the period and also discuss the nuclear capacity factor being proposed by DEC for use in this proceeding in determining the fuel factor to be reflected in rates during the billing period of September 1, 2020 through August 31, 2021 ("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 DEC's nuclear units through the billing period. This exhibit represents DEC's current plan, which is subject to adjustment due to changes in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEC'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 5,389 megawatts ("MWs") of generating capacity, made up as follows:

Oconee -	2,554 MWs
McGuire -	2,316 MWs
Catawba -	519 MWs [1]

The three generating stations summarized above are comprised of a total of seven units. Oconee began commercial operation in 1973 and was the first nuclear station designed, built, and operated by DEC. It has the distinction of being the second nuclear station in the country to have its license, originally issued for 40 years, renewed for up to an additional 20 years by the NRC. The license renewal, which was obtained in 2000, extends operations to 2033, 2033, and 2034 for Oconee Units 1, 2, and 3, respectively.

McGuire began commercial operation in 1981, and Catawba began commercial operation in 1985. In 2003, the NRC renewed the licenses for McGuire and Catawba for up to an additional 20 years each. This renewal extends operations until 2041 for McGuire Unit 1, and 2043 for McGuire Unit 2 and

[1] Reflects DEC's 19.246% ownership of Catawba Nuclear Station.

Catawba Units 1 and 2. The Company jointly owns Catawba with North Carolina Municipal Power Agency Number One, North Carolina Electric Membership Corporation, and Piedmont Municipal Power Agency.

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

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

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

A. The Company operated its nuclear stations in a reasonable and prudent manner during the test period, providing approximately 61% of the total power generated by DEC. During 2019, DEC's seven nuclear units collectively achieved the highest annual net generation and annual capacity in the Company's history. Both Catawba Unit 1 and Oconee Unit 1 established new annual generation records during 2019. The Oconee station, Oconee Unit 3, and McGuire Unit 2 all recorded their second highest annual net output during 2019. DEC's fleet capacity factor of 97.09% achieved during 2019 marked the 20th consecutive year in which DEC's nuclear fleet exceeded a system capacity factor of 90%. All three of the Company's refueling outages in 2019 were completed within allocation, and both Catawba Unit 2 and Oconee Unit 2 entered refueling outages after completing breaker-to-breaker continuous cycle runs.

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

A. The Company's nuclear fleet has a history of performance that consistently exceeds industry averages. The most recently published North American Electric Reliability Council's ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") indicates an average capacity factor of 91.6% for the period 2014 through 2018 for comparable units. The Company's 2019 capacity factor of 97.09% and 2-year average[2] of 96.19% both exceed the NERC average of 91.6%.

Industry benchmarking efforts are a principal technique used by the Company to ensure best practices, and Duke Energy's nuclear fleet continues to rank among the top performers when compared to the seven-other large domestic nuclear fleets using Key Performance Indicators ("KPIs") in the areas of personal safety, radiological dose, manual and automatic shutdowns, capacity factor, forced loss rate, industry performance index, and total operating cost. On a larger industry basis using early release data for 2019 from the Electric Utility Cost Group, all three of DEC's nuclear plants rank in the top quartile in total operating

[2] This represents the simple average for the current and prior 12-month test periods.

cost among the 57 U.S. operating nuclear plants. By continually assessing the Company's performance as compared with industry benchmarks, the Company continues to ensure the overall safety, reliability and cost-effectiveness of DEC's nuclear units.

The superior performance of DEC's nuclear fleet has resulted in substantial benefits to customers. DEC's nuclear fleet has produced approximately 43.9 million MWhs of additional, emissions-free generation over the past 20 years (as compared with production at a capacity factor of 90%), which is equivalent to an additional 9 months of output from DEC's nuclear fleet (based on DEC's average annual generation for the same 20-year period). These performance results demonstrate DEC's continuing success in achieving high performance without compromising safety and reliability.

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

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

Prior to a planned outage, DEC develops a detailed schedule for the outage and for major tasks to be performed, including sub-schedules for particular activities. The Company's scheduling philosophy is to strive for the best possible outcome for each outage activity within the outage plan. For example, if the "best ever" time an outage task was performed is 12 hours, then 12 hours becomes the goal for that task in each subsequent outage. Those individual aspirational goals are incorporated into an overall outage schedule. The Company then aggressively works to meet, and measures itself against, that aspirational schedule. To minimize potential impacts to outage schedules due to unforeseen maintenance requirements, "discovery activities" (walk-downs, inspections, etc.) are scheduled at the earliest opportunities so that any maintenance or repairs identified through those activities can be promptly incorporated into the outage plan.

As noted, the schedule is utilized for measuring outage preparation and execution and driving continuous improvement efforts. However, for planning purposes, particularly with the dispatch and system operating center functions, DEC also develops an allocation of outage time that incorporates reasonable schedule losses. The development of each outage allocation is dependent on maintenance and repair activities included in the outage, as well as major projects to be implemented during the outage. Both schedule and allocation are set aggressively to drive continuous improvement in outage planning and execution.

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

A. If an unanticipated issue that has the potential to become an on-line reliability challenge is discovered while a unit is off-line for a scheduled outage and repair cannot be completed within the planned work window, the outage is extended when in the best interest of customers to perform necessary maintenance or repairs prior to returning the unit to service. The decision to extend an outage is based on numerous factors, including reliability risk assessments, system power demands, and the availability of resources to address the emergent challenge. In general, if an issue poses a credible risk to reliable operations until the next scheduled outage, the issue is repaired prior to returning the unit to service. This approach enhances reliability and results in longer continuous run times and fewer forced outages, thereby reducing fuel costs for customers in the long run. In the event that a unit is forced off-line, every effort is made to safely perform the repair and return the unit to service as quickly as possible.

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

A. Yes. DEC 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 to identify areas in which it can utilize self-critical observation for improvement efforts.

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

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

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

A. There were three refueling outages completed during the test period: McGuire Unit 1 in the spring of 2019, followed by Catawba Unit 2 and Oconee Unit 2 in the fall. All three outages were completed within allocation, and the combined O&M outage costs for the three refueling outages totaled $86 million compared to the combined budget for the three outages of $89.9 million.

The McGuire Unit 1 refueling outage began on March 23, 2019. In addition to refueling, major pump and motor work included replacement of the turbine driven auxiliary feedwater system pump seals, replacement of the 1B2 component cooling pump motor and replacement of the 1C reactor coolant pump seal. Major electrical work included replacement of the 1B main start up transformer, final installation and testing of the emergency supplemental power source diesel generators, and upgrades to the distributed control system. Required Nuclear Electric Insurance Limited inspections were completed on the 1B low pressure turbine and the 1B feedwater pump turbine. Other inspection activities included control rod guide card inspections and reactor head volumetric inspections. After refueling, maintenance, and modifications were completed, the unit returned to service on April 16, 2019, a duration of 24.75 days compared to a 29-day allocation. All outage goals were met.

Following a breaker-to-breaker continuous run of 518 days, Catawba Unit 2 was removed from service on September 14, 2019 for refueling. In addition to refueling, major pump and motor work included replacement of the 2B and 2C reactor coolant pump seals, and replacement of the 2A reactor coolant charging pump motor. The 2C1 heater drain pump and motor, the 2A hotwell pump motor, and the 2A2 component cooling water pump motor were all refurbished. In addition, the 2C condensate booster pump motor was rewound. Major mechanical preventive maintenance and replacement of the 7R cylinder liner was completed on the 2A diesel generator. The 2B reactor coolant system hot leg resistance temperature detector was replaced. Major test and inspection activities included steam generator Eddy Current testing, reactor vessel hot leg ultrasonic testing, 2A feedwater pump turbine inspection, and cleaning and inspection of the main condenser tubes. Main power relay testing for zone "2B" and "2G" was also completed. After refueling, maintenance, and modifications were completed, the unit returned to service on October 9, 2019, a duration of 24.9 days against a 29-day allocation. Following restart from the refueling outage, the turbine was disconnected for 2.03 hours to complete turbine overspeed trip testing.

The Oconee Unit 2 refueling outage began on November 8, 2019 following a 712-day breaker-to-breaker continuous cycle run. In addition to refueling activities, significant scope included replacement of the unit's three low pressure turbine rotors, and the successful completion and testing of a complex modification to the standby shutdown facility letdown line. Electrical work completed included replacement of power circuit breakers PCB-23 and PCB-24, and completion of major preventive maintenance on the main transformer. Several maintenance activities were performed on the reactor coolant pumps, including two pump seal replacements, four oil cooler change-outs and two upper motor bearing inspections. Other pump and motor work included replacement of 2A electro-hydraulic control pump, 2D1 heater drain pump and motor, and 2B1 high pressure injection motor. After refueling, maintenance, and modifications were completed, the unit returned to service on December 12, 2019, for a total outage duration of 33.3 days against an allocation of 34.5 days. Following restart from the refueling outage, the turbine was disconnected for 2.02 hours to complete turbine overspeed trip testing. All outage goals were met.

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

A. The Company proposes to use a 94.39% capacity factor, which is a reasonable value for use in this proceeding based upon the operational history of DEC'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 McGee and exceeds the five-year industry weighted average capacity factor of 91.6% for comparable units as reported in the NERC Brochure during the period of 2014 to 2018.

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

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

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

STEVEN D. CAPPS CONFIDENTIAL EXHIBIT 1

FILED UNDER SEAL

FEBRUARY 25, 2020