PLACE: WebEx Video Conference

DATE: Tuesday, June 9, 2020

TIME: 1:02 p.m. - 1:10 p.m.

DOCKET NO.: E-7, Sub 1228

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Application of Duke Energy Carolinas, LLC, Pursuant to N.C.G.S. 62-133.2 and NCUC Rule R8-55 Regarding Fuel and Fuel-Related Cost Adjustments for Electric Utilities.

VOLUME: 2

Noteworthy Reporting Services, LLC

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P R O C E E D I N G S

CHAIR MITCHELL: All right. Let's come to order. I'm Charlotte Mitchell, Chair of the Utilities Commission. And with me this afternoon by way of remote connection are Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

I now call for hearing Docket Number E-7, Sub 1228, which is the application by Duke Energy Carolinas, LLC, pursuant to North Carolina General Statute 62-133.2 and Commission Rule R8-55 regarding Fuel-Related Adjustments for Electric Utilities.

G.S. 62-133.2 provides for annual fuel charge adjustment proceedings for electric utilities engaged in the generation or production of electricity by fossil or nuclear fuels. Commission Rule R8-55 provides the fuel charge adjustment proceedings for DEC held the first Tuesday of June -- will be held the first Tuesday of June each year. The rule further provides that DEC shall file direct testimony and exhibits in support of fuel charge adjustments and public notice of its proceedings prior to the hearing.

On February 25, 2020, DEC filed its application to adjust its fuel-related charges along with its supporting testimony and exhibits. On March 17, 2020, the Commission issued its order scheduling hearing, requiring filing of testimony, establishing discovery guidelines, and requiring public notice. On May 7, 2020, DEC filed supplemental testimony and revised exhibits in support of its application.

All right. I'm picking up some noise, so I'm going to ask that you-all check to make sure that you are on mute. Please make sure you mute your line.

All right. Petitions to intervene in this docket were timely filed by Carolina Industrial Group for Fair Utility Rates, III; North Carolina Sustainable Energy Association; the Sierra Club; Carolina Utility Customers Association, Inc. These petitions to intervene were allowed by separate orders of the Commission. The intervention and participation by the Public Staff in this proceeding is recognized pursuant to North Carolina General Statute 62-15.

On May 18, 2020, the Public Staff filed the testimony of Dustin Metz and the affidavit of Jenny Li. On May 18, 2020, the Sierra Club also filed its testimony and exhibits.

On May 28, 2020, DEC filed -- DEC filed its rebuttal testimony. On May 29, 2020, the Commission issued an order scheduling remote hearings to receive expert witness testimony. On May 29, 2020, DEC, the Sierra Club, and the Public Staff filed a joint motion requesting that all witnesses be excused from attending this hearing and that the prefiled testimony, exhibits, work papers, and affidavits of the respective witnesses be received into evidence and made a part of the record in this matter.

On June 1, 2020, the Commission issued its order excusing all witnesses from attending the hearing. On June 2nd and June 3rd, 2020, DEC, along with the Sierra Club, CIGFUR, NCSEA, CUCA, and the Public Staff, filed dockets in this docket indicating their assent to a remote expert witness hearing and its associated conditions and logistics. Finally, on June 5th, DEC filed its affidavit of publication regarding public notice.

All right. That brings us to today. I now call upon counsel for the parties to announce their appearances beginning with the applicant.

MR. JIRAK: Good afternoon, Chair Mitchell. Jack Jirak on behalf of Duke Energy Carolinas.

MR. KAYLOR: Good afternoon. Robert Kaylor on behalf of Duke Energy Carolinas.

CHAIR MITCHELL: Good afternoon, gentlemen.

MS. HICKS: Good afternoon. Warren Hicks on behalf of the Carolina Industrial Group for Fair Utility Rates, III.

CHAIR MITCHELL: Good afternoon, Ms. Hicks.

MR. MOORE: Good afternoon. This is Tirrill Moore appearing on behalf of the Sierra Club.

CHAIR MITCHELL: Good afternoon, Mr. Moore.

MR. SMITH: Good afternoon. Ben Smith appearing on behalf of the North Carolina Sustainable Energy Association.

CHAIR MITCHELL: Good afternoon,

Mr. Smith.

MS. DOWNEY: Good afternoon, Chair Mitchell, Commissioners. Dianna Downey on behalf of the Public Staff representing the Using and Consuming Public.

MS. THOMPSON: Good afternoon, Chair Mitchell, members of the Commission. Gudrun Thompson, also appearing on behalf of Sierra Club. Just wasn't able to get to my mute button quickly enough.

CHAIR MITCHELL: Good afternoon, Ms. Thompson. Good afternoon, Ms. Downey.

All right. Anyone making an appearance for CUCA?

(No response.)

CHAIR MITCHELL: Okay. Any preliminary matters to be addressed before we begin?

MR. JIRAK: Nothing from Duke Energy Carolinas.

CHAIR MITCHELL: All right. With that, the case is with you, Mr. Jirak.

MR. JIRAK: Thank you, Chair Mitchell. As you noted, the Commission's June 1, 2020, order has excused witnesses from appearing and also received the prefiled direct, supplemental, and rebuttal testimony, exhibits, and work papers in the record. So, at this time, just to clarify the record, we would move that all such testimony be entered into the record in this proceeding along with the application that Duke's witnesses' testimony supports. And if you prefer, Commissioner -- Chair Mitchell, I can walk through each piece of testimony, but if the record is clear enough based on that motion, we can move on.

CHAIR MITCHELL: I'll accept the motion. Hearing and seeing no objection to your motion, Mr. Jirak, testimony and exhibits -- prefiled testimony and exhibits of DEC shall be admitted into the record. Exhibits marked as prefiled, application shall be admitted into the record as well.

(Application by Duke Energy Carolinas, LLC; McGee Exhibits 1 through 6; McGee Workpapers 1 through 7, 7b, and 8 through 10; Revised McGee Workpapers 7a, 10a, 10b, and 11 through 13; Supplemental Revised McGee Exhibit 1; Supplemental McGee Exhibit 2;

Supplemental Revised McGee Exhibit 3; Supplemental McGee Exhibits 4 through 6; Supplemental McGee Workpapers 1 through 3, 5, 6, 8, 10, 10b, and 11 through 13; Supplemental Revised Workpapers 4, 7, 7a, 7b, and 9; Phipps Exhibits 1 and 2; Phipps Confidential Exhibits 3 and 4; and Capps Confidential Exhibit 1 were admitted into evidence.)

(Whereupon, the prefiled direct, supplemental, and rebuttal, testimony of Kimberly D. McGee, prefiled direct testimony of Brett Phipps, prefiled direct testimony of Regis Repko, prefiled direct testimony of Kevin Y. Houston, and prefiled direct testimony of Steven D. Capps was copied into the record as if given orally from the stand.)

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.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**SUPPLEMENTAL TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF KIMBERLY D. 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 D. McGee. My business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes, on February 25, 2020, I caused to be pre-filed with the Commission my direct testimony and 6 exhibits and 14 supporting workpapers.

Q. YOUR SUPPLEMENTAL TESTIMONY INCLUDES THREE (3) REVISED EXHIBITS AND FIVE (5) REVISED SUPPORTING WORKPAPERS. WERE THESE SUPPLEMENTAL EXHIBITS AND WORKPAPERS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits and workpapers were prepared by me and consist of the following:

McGee Revised Exhibit 1: Summary Comparison of Fuel and Fuel-Related Costs Factors.

McGee Revised Exhibit 2: Calculation of the Proposed Fuel and Fuel-Related Cost Factors.

McGee Revised Exhibit 3: Calculation of the Proposed Experience Modification Factor ("EMF") rate.

McGee Revised Workpaper 4: Projected fuel and fuel related costs

McGee Revised Workpaper 7: Calculation of Allocation percentages based on Projected Test Period Sales

McGee Revised Workpaper 7a: Calculation of Allocation percentages based on Normalized Test Period Sales

McGee Revised Workpaper 7b: Calculation of Allocation percentages based on Projected Test Period Sales and NERC 5 year average

McGee Revised Workpaper 9: Calculation of total projected reagent and (gain)/loss on sale of by-products

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

A. The purpose of my testimony is to present revised rates reflecting the impacts related to two updates to numbers presented in my direct exhibits. The first update relates to the proposed EMF increment for the experienced under-recovery of fuel and fuel related costs, pursuant to NCUC Rule R8-55(d)(3), which allows the Company to incorporate the fuel and fuel-related cost recovery balance up to thirty (30) days prior to the hearing. The Company elects this option and supplements the direct testimony and exhibits to include the fuel and fuel-related cost recovery balance as of the 15 months ended March 31, 2020. The second update revises the projected net (gain)/loss on the sale of steam which is included in estimated system fuel and fuel-related costs for the billing period. Based on discussions with the North Carolina Public Staff, the Company discovered that certain assumptions used in the calculation of estimated revenue from the sale of steam from its combined heat and power generating facility were out of date. The Company is increasing the estimated steam revenues included in net gain/loss on the sale of by-products for the billing period as a result of updating the underlying assumptions in its calculations.

Q. HOW DID THE FUEL AND FUEL-RELATED COST RECOVERY BALANCE CHANGE IN THE THREE (3) MONTHS BEING INCORPORATED?

A. The Company experienced an over-collection of $52,248,875 during the months January through March 2020. As shown on McGee Revised Exhibit 3, the incorporation of the update period over-collection balance resulted in a lower under-recovered balance at March 31, 2020 of $57,087,941. Incorporating the over-collections experienced during January – March 2020 will reduce the EMF rates charged to customers.

Q. **WHAT WAS THE CHANGE IN FUEL COSTS DUE TO THE UPDATE IN STEAM REVENUE PROJECTIONS FOR THE BILLING PERIOD?**

A. These revenues reduce total fuel and fuel-related costs by $928,459.

Q. WHAT IS THE TOTAL RATE IMPACT OF THESE UPDATES?

A. The NC Retail Total Fuel Costs were decreased by $ 52,731,001 from the amounts filed in my direct Exhibit 2, Schedule 1, page 3. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on McGee Revised 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	1.6027	1.7583	1.6652	1.6816
EMF Increment (Decrement)	0.0364	0.0666	0.2658	0.0975
Net Fuel and Fuel Related Costs Factors	1.6391	1.8249	1.9310	1.7791

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

A. The revised proposed fuel and fuel-related costs factors will result in a 3.01% decrease on customers' bills, as compared to the previously filed decrease of 1.90%.

Q. DOES THIS CONCLUDE YOUR PRE-FILED SUPPLEMENTAL 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	)	**REBUTTAL TESTIMONY**
R8-55 Relating to Fuel and Fuel-Related	)	**OF KIMBERLY D. MCGEE**
Charge Adjustments for Electric Utilities	)	
	)	
	)	

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

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

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. On February 25, 2020, I caused to be pre-filed with the Commission my direct testimony and exhibits and supporting workpapers. On May 7, 2020, I caused to be pre-filed with the Commission my supplemental direct testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purposes of my rebuttal testimony is to respond to the testimony of John A. Rosenkranz on behalf of the Sierra Club.

Q. PLEASE SUMMARIZE THE TESTIMONY.

A. The Company's application (including the supporting testimony, exhibits and workpapers) are fully compliant with applicable law and provide more than sufficient information to demonstrate the reasonableness and prudence of the Company's fuel costs, including its natural gas costs. The sufficiency of the Company's application should be evaluated based on the requirements of applicable law and not on the subjective judgment of particular intervenors, particularly given that intervenors have the right to obtain any information that they believe to be necessary through the well-established discovery process. Nevertheless, the Company has engaged with Sierra Club on these issues subsequent to the submission of Sierra Club's testimony and has achieved a mutually acceptable solution whereby the Company will provide to Sierra Club in future proceedings reports that should provide the vast majority of the information identified by Witness Rosenkranz.

Q. WHAT IS THE PURPOSE OF THIS PROCEEDING?

A. The purpose of a fuel proceeding is to review the Company's proposed fuel rates.

Q. HAS WITNESS ROSENKRANZ RECOMMENDED ANY CHANGES TO THE FUEL RATES PROPOSED BY THE COMPANY?

A. No. Witness Rosenkranz has not recommended any changes to the Company's proposed fuel rates. Instead, Witness Rosenkranz has made certain allegations regarding the amount of information provided by the Company in this proceeding related to the Company's natural gas costs.

Q. PLEASE COMMENT GENERALLY ON WITNESS ROSENKRANZ'S ALLEGATION THE COMPANY HAS NOT PROVIDED SUFFICIENT INFORMATION IN THIS PROCEEDING TO ESTABLISH ITS TEST PERIOD FUEL AND FUEL-RELATED COSTS WERE REASONABLE AND PRUDENTLY INCURRED.

A. I strongly disagree with this assertion. The Company's application conformed in all respects with the requirements outlined in Commission Rule R8-55, including the specific information required to be included in a fuel rider application under R8-55(e). Compliance with the Commission's clear and objective information requirements is the appropriate standard for evaluating the sufficiency of the Company's application and not Witness Rosenkranz's subjective judgement regarding what he believes constitutes "sufficient" information.

Q. HAS ANY OTHER PARTY TO THIS PROCEEDING IDENTIFIED ANY ASPECT OF THE COMPANY'S FILING THAT DOES NOT CONFORM TO THE COMMISSION'S FILING REQUIREMENTS?

A. No. No other party in this proceeding, including Public Staff, has identified any aspect of the Company's filing that is not in compliance with applicable law.

Q. IS THE CONTENT AND STRUCTURE OF THE COMPANY'S APPLICATION IN THIS CASE CONSISTENT WITH ITS FILING IN RECENT FUEL CASES?

A. Yes. The content and structure of the Company's application in this proceeding is identical to that of all recent fuel rider applications.

Q. IF SIERRA CLUB RECOMMENDS CHANGES TO THE FILING REQUIREMENTS FOR THE COMPANY'S ANNUAL FUEL PROCEEDING, WHAT IS THE APPROPRIATE ROUTE TO IMPLEMENT SUCH CHANGES?

A. While I am not an attorney, I have been advised by counsel that Sierra Club is free to petition the Commission to initiate a rulemaking proceeding to modify Commission Rule R8-55 if it believes the existing rule is insufficient in any respect.

Q. WHAT OTHER AVENUES DOES SIERRA CLUB HAVE TO GATHER INFORMATION?

A. Sierra Club has the ability to pursue discovery regarding the Company's request.

Q. DID SIERRA CLUB IN FACT ISSUE DISCOVERY TO THE COMPANY IN THIS PROCEEDING?

A. Yes. Sierra Club did issue discovery to the Company and the Company responded to all such requests in accordance with the well-established discovery practices before the Commission.

Q. WITNESS ROSENKRANZ ALSO ALLEGES DEFICIENCIES IN THE COMPANY'S MONTHLY FUEL REPORTS. PLEASE COMMENT ON THIS ALLEGATION.

A. Witness Rosenkranz conflates two related but separate issues: (1) the required contents of the Company's fuel rider application as required under Commission Rule R8-55(e) and (2) the required contents of the Monthly Fuel Reports under Commission Rule R8-52. As discussed above, the Company's fuel rider application conforms in all respects with the requirements of Commission Rule R8-55(e). Furthermore, the Company's Monthly Fuel Reports, filed in Docket No. E-7, Sub 1234, comply with all requirements under Commission Rule R8-52.

Q. PLEASE PROVIDE BACKGROUND ON THE COMPANY'S MONTHLY FUEL REPORTS.

A. The contents of the Monthly Fuel Report are established by Commission Rule R8-52. Moreover, the format of the Monthly Fuel Report was also established by the Commission in its May 1, 1984 Order in Docket No. E-100, Sub 47 ("Monthly Fuel Report Order").

Q. HAS THE COMPANY COMPLIED WITH COMMISSION RULE R8-52 AND THE COMMISSION'S MONTHLY FUEL REPORT ORDER?

A. In all material respects, yes. The Company has elected to provide all information that is not confidential or sensitive in nature within its publicly filed Monthly Fuel

Report. In the Monthly Fuel Report Order, the Commission noted that the confidentiality of source of purchases, FOB mine costs of coal and freight costs of coal should be protected to the extent reasonable and that such information should be made available to intervenors on an as-needed basis. Consistent with this direction, the Company has not historically included confidential information in the Monthly Fuel Reports but has made it available for review during the annual fuel filing review process.

Q. PLEASE PROVIDE A HIGH LEVEL DESCRIPTION OF WHAT INFORMATION CONCERNING NATURAL GAS IS PROVIDED IN THE COMPANY'S MONTHLY FUEL REPORTS.

A. The Company's Monthly Fuel Reports include summary information about monthly fuel costs, purchases, and consumption. Schedule 2 of the Monthly Fuel Report includes details of fuel costs at the general ledger account level. The total cost of gas burned by type of generating plant is shown under the Subheading Other Generation – Account 547. Schedule 5 includes the total delivered cost of purchases of natural gas, the average cost per Mbtu purchased, the total delivered cost of gas burned, total Mbtus burned and average cost per Mbtu burned on a per plant basis. Schedule 6 is the fuel and fuel consumption and inventory report. The Company does not maintain an inventory of natural gas at the plant level and thus the report shows all amounts received during the period as burned during the period at all gas generating stations.

Q. TURNING NOW TO THE SPECIFIC INFORMATION DEFICIENCIES ALLEGED BY WITNESS ROSENKRANZ, WHERE DOES THE

COMPANY IDENTIFY THE COST OF NATURAL GAS TRANSPORTATION IN ITS FUEL APPLICATION AND MONTHLY FUEL REPORTS?

A. The cost of natural gas transportation is included in the total cost of natural gas consumed. In the Company's fuel application, this information is contained in Exhibit 6, Schedules 2, 5 and 6 and in the Monthly Fuel Reports, the information is included in GL account 547 and is shown by generating type.

Q. WHERE IN THE MONTHLY FUEL REPORTS DOES THE COMPANY PROVIDE DETAILS REGARDING ITS NATURAL GAS CONSUMPTION?

A. The details of natural gas consumption can be found on Schedules 5 and 6 of the Monthly Fuel Reports.

Q. WHERE IN THE MONTHLY FUEL REPORT DOES THE COMPANY PROVIDE INFORMATION CONCERNING ITS NATURAL GAS INVENTORIES?

A. The Company does not maintain an inventory of natural gas at the plant level but Schedule 6 reflects the MCFs received and the MCFs consumed by gas generation plant.

Q. PLEASE COMMENT ON WITNESS ROSENKRANZ'S ALLEGATION THAT THE COMPANY SHOULD BE REQUIRED TO IDENTIFY THE DIFFERENCE BETWEEN THE COSTS OF NATURAL GAS PURCHASED AND THE COSTS OF NATURAL GAS BURNED.

A. As noted above, the Company does not maintain an inventory of natural gas at the plant level. Instead, any gas purchased and not consumed in a given period is pooled at two off-site storage facilities and used as needed to manage intraday supply adjustments on the pipeline, including on weekends and holidays when the gas markets are closed, in order to ensure reliable generation supply and mitigate potential pipeline imbalance penalties.

Because it is not possible to distinguish between individual molecules of gas to determine when they were consumed, the Company includes in its monthly fuel filings the cost of both that month's physical gas purchases and the weighted average cost of inventory change. These costs are then allocated across the DEC and DEP generating units based on the methodology prescribed under the approved Affiliate Asset Management and Delivered Supply Agreement ("AMA") implemented in January 2013.

Q. WITNESS ROSENKRANZ ALSO IDENTIFIES A SUBSTANTIAL AMOUNT OF ADDITIONAL INFORMATION THAT HE BELIEVES IS NECESSARY TO ESTABLISH THE REASONABLENESS AND PRUDENCE OF THE COMPANY'S NATURAL GAS COSTS. PLEASE EXPLAIN WHY YOU BELIEVE THAT THE INFORMATION INCLUDED IN THE COMPANY'S APPLICATION IS SUFFICIENT TO ESTABLISH THE REASONABLENESS AND PRUDENCE OF THE COMPANY'S COSTS.

A. As an initial matter, because its application satisfied the express requirements of the applicable Commission Rule (R8-55), the Company believes that, as a matter of law, it has provided sufficient information to demonstrate the reasonableness and prudence of its fuel costs. Furthermore, in its application, the Company provides total delivered cost of fuel purchased and burned, which can be benchmarked against peers and market prices for purposes of assessing the reasonableness and prudence of the Company's actions.

Q. FINALLY, WITNESS ROSENKRANZ SEEKS TO IMPOSE CERTAIN REQUIREMENTS ON THE COMPANY'S TESTIMONY IN FUTURE FUEL PROCEEDINGS. PLEASE RESPOND.

A. Once again, the Company reaffirms its position that its application complies in all respects with applicable law. In addition, there is no basis in Commission practice for parties to seek to dictate the contents of future direct testimony, particularly given that if Sierra Club believes that more information is needed, it is free to seek to modify the applicable Commission rule or, in the alternative, pursue such information through discovery rather than seek to impose additional testimony requirements. Further and more specifically, while Witness Rosenkranz seeks to impose an obligation to offer testimony regarding "changes to natural gas supply resources commitments" and a detailed explanation of how entering or extending specific agreements "will benefit customers," this information is either already provided in the Company's application or available for review through the standard data request process. For instance, DEC Witness Phipps addresses in his testimony the Company's fossil fuel procurement practices and the intended customer benefits of these practices. Phipps Exhibit 1 summarizes the Company's Fossil Fuel Procurement Practices and also includes additional discussion of how the Company establishes its consumption needs not only for natural gas, but coal and fuel oil as well. In fact, Witness Phipps' testimony also included, at the direction of the Commission, a detailed evaluation of historic natural gas price fluctuations and its forecasting and hedging programs.

Q. PLEASE DESCRIBE THE COMPANY'S FURTHER ENGAGEMENT WITH SIERRA CLUB WITH RESPECT TO THESE ISSUES.

A. While the Company continues to affirm that its fuel application is fully compliant with applicable law and reiterates that it has complied with all discovery requests, the Company also engaged with Sierra Club subsequent to the submission of their pre-filed direct testimony to assess whether it would be possible to provide some or all of the additional information that Witness Rosenkranz identified in his testimony that was not already made available to Sierra Club. Through those discussions, the Company and Sierra Club have reached a mutually acceptable understanding pursuant to which the Company will make available to Sierra Club in future fuel proceedings upon their request certain reporting that will include the vast majority of the information requested.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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.

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 DEC Operational Results	2014-2018 NERC Average	Nbr of Units
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	)	**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.

MR. JIRAK: Thank you. That's all that we have.

CHAIR MITCHELL: All right. Thank you, Mr. Jirak.

I will hear from the intervenors. Let's begin with CIGFUR.

MS. HICKS: Thank you, Chair Mitchell. Nothing from CIGFUR.

CHAIR MITCHELL: Okay. Thank you, Ms. Hicks.

NCSEA?

MR. SMITH: Thank you, Chair Mitchell. Nothing from NCSEA.

CHAIR MITCHELL: Okay. Thank you, Mr. Smith.

Sierra Club?

MR. MOORE: I would just add that the May 29th motion I made with DEC and the Public Staff included the testimony of Sierra Club witness, John Rosenkranz. So I would just, out of an abundance of caution, move his testimony and exhibits into the record as well.

CHAIR MITCHELL: All right. Thank you, Mr. Moore. Hearing and seeing no objection to your motion, your motion will be allowed. Exhibits marked as prefiled.

(Rosenkranz Exhibits 1 through 3 were admitted into evidence.)

(Whereupon, the prefiled direct testimony of John A. Rosenkranz was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

In the Matter of: Application of Duke Energy Carolinas, LLC Pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))))	**DIRECT TESTIMONY OF JOHN A. ROSENKRANZ ON BEHALF OF THE SIERRA CLUB**

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is John A. Rosenkranz. I am Principal with North Side Energy, LLC. My business address is 56 Washington Drive, Acton, MA 01720.

Q. Please describe your professional background and experience.

A. I have more than 30 years of experience in the areas of natural gas supply planning, utility regulation, and gas and electric project development. I have been an independent consultant since 2006. Previously, I was responsible for negotiating and managing long-term natural gas supply and transportation contracts for power generation, and prepared market and rate studies for interstate pipeline and gas storage projects. I received a BA degree in economics from George Washington University, and completed all course and examination requirements for a doctorate in economics at Northwestern University. My Experience Statement is attached as Exhibit 1.

Q. Have you previously testified before the North Carolina Utilities Commission?

A. No, I have not.

Q. Have you testified before other state, provincial, or federal regulators?

A. Yes. I have testified before the Maine Public Utilities Commission, the New Hampshire Public Utilities Commission, the Massachusetts Department of Public Utilities, the Arizona Corporation Commission, and the Ontario Energy Board. I have also submitted testimony in proceedings before the New Jersey Board of Public Utilities and the Federal Energy Regulatory Commission.

Q. Please describe your experience with natural gas supply for electricity generation.

A. From 2000 to 2006, I was responsible for negotiating gas transportation and storage services agreements for new gas-fired generation facilities developed by Calpine Corporation in the U.S. and Canada. From 2006 to 2016, I advised the Ontario Power Authority on power generators' proposals to contract for gas transportation and storage services that would be eligible for cost reimbursement under electricity purchase contracts.

Q. Please describe your experience with utility gas cost recovery proceedings.

A. Over the last decade, I have reviewed natural gas utility cost recovery filings as a consultant to the Maine Public Advocate and New Jersey Division of Rate Counsel.

Q. On whose behalf are you sponsoring testimony in this proceeding?

A. I am testifying on behalf of the Sierra Club.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to examine whether the information that Duke Energy Carolinas ("DEC") provided with its February 2020 application in this case is adequate to support the requested cost recovery. I evaluate DEC's filing based first, on whether DEC has met the minimum reporting requirements set out in Commission Rule R8-55, and second, on whether the information provided by DEC is sufficient to make a determination as to whether the test period natural gas supply costs were reasonable and prudently incurred.

Q. Please summarize your findings and recommendations.

A. From 2011 to 2019, DEC's fuel and fuel-related costs for natural gas supply increased from approximately $50 million to more than $400 million per year, and DEC entered into new long-term commitments for interstate gas transportation services. However, even though natural gas costs now account for a much larger share of DEC's fuel and fuel-related costs, the data that DEC provides to support the recovery of gas supply costs appears not to have changed.

Based on the information provided, it is not possible to determine whether DEC's test period fuel and fuel-related costs were reasonable and prudently incurred. DEC should expand the information on natural gas supply quantities and costs that it includes with the annual fuel cost adjustment application. At a minimum, DEC should provide: (a) details on the sources and uses of natural gas, (b) a full description of the gas transportation and storage services used to supply DEC plants, and the associated fixed reservation charges, and (c) net revenues from natural gas sales and the transportation capacity releases. DEC should also be prepared to provide daily gas use data for each plant, and daily scheduled quantities for each firm gas transportation service.

Q. Please explain how your testimony is organized.

A. Section II describes the natural gas supply costs that DEC is seeking to recover in this proceeding. Section III addresses DEC's commitments to gas transportation services, and explains why it is important for DEC to actively manage these services to reduce customer costs. In Section IV I examine the natural gas supply quantity and cost information that DEC provided to support test period cost recovery, and make recommendations concerning the additional information that DEC should provide.

II. ANNUAL FUEL CHARGE ADJUSTMENT

Q. What is the purpose of the annual fuel charge adjustment?

A. North Carolina electric public utilities that use fossil fuels to generate electricity for retail electric service are permitted to adjust their rates each year to reflect changes in the cost of fuel and fuel-related costs. The fuel cost adjustment is based on the projected costs for the billing period, and actual costs that were over-recovered or under-recovered during the test period. The utility has the burden of proof to show that test period costs were reasonable and prudently incurred.

For DEC, the test period is the calendar year prior to the year in which the application is filed, and the billing period is the twelve-month period starting September 1 of the year in which the application is filed.

Q. What are the fuel and fuel-related costs?

A. N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 define "cost of fuel and fuel-related costs" to mean the cost of fuel burned and the cost of fuel transportation, adjusted for any net gains or losses from sales of fuel and other fuel-related costs components.

Q. How does DEC currently use natural gas?

A. DEC consumed natural gas at seven generating stations during the 2019 test period. This includes three combined-cycle ("CC") plants (Buck, Dan River, and W.S. Lee), three combustion turbine ("CT") plants (Lincoln, Rockingham, and Mill Creek), and a steam plant that co-fires natural gas with coal (Cliffside). The three combined-cycle plants accounted for 81 percent of DEC's total natural gas consumption (Table 1). Natural gas used in combustion turbines and gas for co-firing each accounted for just under 10 percent of the total. DEC also used natural gas for commissioning the Clemson combined heat and power ("CHP") plant.

Table 1: Natural Gas Use at DEC Plants, Calendar 2019[1]

	Plant Type	Gas Burned (BBtu)	Percent
1	Combined Cycle	99,790.5	80.6%
2	Combustion Turbine	12,167.4	9.8%
3	Steam (Co-Firing)	11,792.8	9.5%
4	Other Steam & CHP	20.0	<0.1%
5	Total	123,770.7	100.0%

Natural gas use for the September 1, 2020 to August 31, 2021 billing period is projected to reach 201,900 BBtu.[2] DEC attributes the expected increase of 63 percent from the 2019 test period to the start of co-firing at the Belews Creek

[1] 2019 Monthly Fuel Reports, Docket No. E-7, Sub 1198.
[2] Natural gas quantities are shown as million British Thermal Units (MMBtu) and billion Btu (BBtu).

and Marshall generating stations, and an expected increase in generation from the Lincoln combustion turbines.[3]

Q. What portion of test period fuel and fuel related costs were related to natural gas?

A. DEC proposes to recover $405 million for natural gas supply costs incurred during the 2019 test period. As is shown in Table 2, these costs account for 23 percent of the total reported fuel and fuel related costs of $1,750 million. By comparison, natural gas supply costs for calendar 2011 were $51 million, which was less than three percent of the total.

Table 2: Natural Gas Costs vs. Total Fuel Costs, 2011 and 2019

	Plant Type	Calendar 2011[4] (000)	Calendar 2019[5] (000)
1	Combined Cycle	$9,668.2	$322,366.7
2	Combustion Turbine	$41,155.6	$40,328.3
3	Steam	-	$42,380.5
4	Combined Heat and Power	-	$54.7
5	Total Natural Gas Costs	$50,823.8	$405,130.2
6	Total Fuel & Fuel-Related Costs	$1,918,301.0	$1,750,175.4

Q. How do the Duke Energy utilities manage natural gas supplies for their North Carolina and South Carolina plants?

A. The responsibility for managing natural gas supplies for the DEC and DEP power plants is divided into two categories. The first category involves decisions to enter into long-term arrangements with intrastate and interstate transporters to connect generating plants to a source of natural gas supply. These commitments are made by the individual utility. For DEC, these

[3] Direct Testimony of Brett Phipps, page 7.
[4] McManeus Exhibit 8, Docket No. E-7, Sub 1002 (March 7, 2012).
[5] McGee Exhibit 6, Schedule 2.

commitments include contracts with local distribution companies ("LDCs"), long-term contracts with Transcontinental Gas Pipe Line Company ("Transco") for interstate gas transportation, and commitments for future gas transportation service with Atlantic Coast Pipeline ("ACP").

The second category involves decisions to acquire shorter-term gas supply resources, buy natural gas, and optimize the value of gas supply resources under contract. Under the "Asset Management and Delivered Supply Agreement" that was implemented in January 2013, DEC, as the designated Asset Manager, manages these activities on a combined basis for both DEC and DEP.[6] DEP assigns its gas transportation and storage assets to DEC, and the total costs are allocated between the two utilities.

III. NATURAL GAS TRANSPORTATION AND STORAGE SERVICES

Q. How is natural gas delivered to the DEC generating stations?

A. With the exception of the Cliffside generating station, which is connected to Public Service of North Carolina, and the Clemson CHP plant, which is connected to Fort Hill Natural Gas Authority, the DEC generating stations are connected to the Piedmont Natural Gas distribution system.[7] DEC has agreements with the connecting LDCs to receive gas from Transcontinental Gas Pipe Line Company ("Transco") and redeliver the gas to the plant. These agreements specify the quantity of gas that the LDC is obligated to receive and redeliver on any day.

[6] Phipps Exhibit 1, p. 1.
[7] DEC Response to Sierra Club Data Request 1-8, attached as Exhibit 2.

Q. Does DEC also hold long-term contracts for interstate transportation and storage services?

A. Yes. During the test period DEC had long-term contracts with Transco for 151,560 MMBtu/day of firm gas transportation service (Table 3). This pipeline capacity allows DEC to buy gas at various points along the pipeline, and deliver the gas to the LDCs in North Carolina and South Carolina that connect to the DEC generating plants.[8] DEC also holds a long-term contract for firm storage service with Mississippi Hub Storage, which connects with Transco in Simpson County, MS.[9]

Table 3: DEC Long-Term Transportation Contracts on Transco[10]

	Contract Number	Quantity (MMBtu/day)	Start Date	Expiration Date
1	9109922	60,000	5/1/2011	4/30/2031
2	9139583	16,560	7/1/2017	10/31/2017[11]
3	9172961	75,000	3/1/2016	1/31/2023
4	Total	151,560		

Q. Is all of the natural gas used at DEC plants transported on contracts held by DEC or DEP?

A. No. Because there is a market for natural gas delivered at Transco meters in North Carolina and South Carolina, DEC has a choice to either source gas at points outside the market area and contract for interstate pipeline capacity, or buy "delivered" gas. During calendar 2019, of the 308,682.3 BBtu of natural gas purchased for DEC and DEP plants, 151,171.6 BBtu (49 percent) was delivered by gas suppliers at pipeline delivery meters in North Carolina and

[8] DEC has other interstate gas transportation agreements for biogas used at its Dan River plant.
[9] Mississippi Hub Index of Customers report, at http://www.gasnom.com/ip/mississippihub/.
[10] Transco Index of Customers Report, at http://www.1line.williams.com/Transco/index.html.
[11] After the end of the contract term this became an "evergreen" contract that DEC can terminate, subject to the applicable notice provisions.

South Carolina.[12] The remaining 156,510.7 BBtu, or 428,796 MMBtu/day, was transported using interstate pipeline capacity under contract to DEC or DEP.

Q. Does DEC have other commitments for interstate pipeline capacity?

A Yes. DEC has committed to 272,250 MMBtu/day of firm transportation service on ACP. ACP is a proposed new pipeline that would connect gas supply areas in West Virginia to markets in Virginia and North Carolina. DEC's parent company, Duke Energy, has a 47 percent ownership interest in ACP.[13] The ACP capacity would increase the amount of interstate pipeline capacity held by DEC under long-term contracts by 180 percent, from 151,560/MMBtu per day to 423,810 MMBtu/day.

Q. What is the status of the ACP project?

A. ACP had originally proposed a start date of November 1, 2018. In the Quarterly Status Report filed on February 17, 2020 in Docket No. E-7, Sub 1062, DEC states that ACP is now expected to go into service in early 2022, and the construction cost for the project is estimated to be approximately $8 billion. This is an increase of more than 50 percent from the $5.14 billion estimate in ACP's Federal Energy Regulatory Commission ("FERC") certificate application.[14]

Q. Has the Commission determined that DEC's decision to commit to ACP service is prudent?

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[12] DEC Response to Sierra Club Data Request 1-5, attached as Exhibit 3.
[13] Duke Energy Security and Exchange Commission Form 10-K for 2019, p 18.
[14] Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, FERC Docket No. CP15-554, September 18, 2015.

A. No, it has not. The Commission's order accepting the DEC and DEP affiliate agreements with ACP makes clear that the recovery of ACP costs in rates will be addressed in a future proceeding.

> …for ratemaking purposes, the authorizations to pay compensation provided by this Order do not constitute approval of the amount of compensation paid pursuant to the Agreements, and the authority granted by this Order is without prejudice to the right of any party to take issue in a future proceeding with any provision of the Agreements and with DEC's and DEP's management of their pipeline capacity resources.[15]

Q. How do long-term contracts for gas transportation service, such as DEC's commitments with Transco and ACP, create risks for utility customers?

A. Long-term contracts with interstate pipelines commit the contracting party (the "shipper") to pay a fixed monthly charge to reserve pipeline capacity over the term of the agreement. The monthly reservation charge may be based on a negotiated rate that is fixed over the term, or on the tariff rate approved by FERC, which is subject to change. If the value of the capacity falls, either because the market price of natural gas at the receipt point(s) listed in the gas transportation agreement declines relative to the market price at the delivery point(s), or because there is an increase in the tariff rate, the cost of holding capacity on the pipeline may exceed the cost savings obtained from buying gas in an upstream market.

Q. How do utilities manage gas transportation contracts to mitigate these risks?

A. There are three mechanisms that electric and gas utilities can use to obtain additional value from firm transportation capacity, and mitigate their customers' exposure to fixed pipeline charges.

[15] "Order Accepting Affiliate Agreements, Allowing Payment Thereunder and Granting Limited Waiver of Code of Conduct", N.C.U.C. Docket No. E-2, Sub 1052 (October 29, 2014), at 6.

Third-Party Sales – The utility uses the firm transportation service to buy natural gas at pipeline receipt points where prices are relatively low, and resell gas at delivery points where prices are relatively high. The margin recovered on behalf of customers is the difference between the sales price and the purchase price, minus the variable pipeline transportation cost.

Capacity Release - FERC rules allow a shipper holding firm transportation capacity on interstate pipelines to temporarily resell its rights to a replacement shipper. The payments made by the replacement shipper are credited to the releasing shipper by the pipeline.

Asset Management Arrangements ("AMAs") – An AMA combines a capacity release with a gas sales transaction. The utility releases pipeline capacity to a natural gas supplier (the "Asset Manager") and has rights to buy delivered gas from the Asset Manager at a defined price. The Asset Manager makes a negotiated payment to the utility to the use the pipeline capacity over the term of the AMA.

Q. Is contracting for firm gas transportation service a one-time decision that need not be revisited?

A. No, it is not. A utility should continually re-evaluate its commitments to firm gas transportation services as fuel requirements and gas and electric market conditions charge. Precedent agreements for new pipelines and pipeline expansion projects generally include a right to terminate if major project milestones are not met by the dates specified in the agreements. In addition, after service starts, the utility can choose whether or not to renew or extend the service when the initial term expires.

IV. REPORTING REQUIREMENTS

Q. Does the DEC fuel cost adjustment application include the information needed to support the recovery of test period natural gas supply costs?

A. No. The information provided by DEC is not adequate to support a determination as to whether the gas fuel and fuel-related costs were reasonable and prudently incurred.

Q. What information is DEC supposed to include with the fuel cost filings?

A. Commission Rule R8-55(e) defines the minimum information and data requirements for the annual fuel cost adjustment application.[16] This information includes:

- Procurement practices and inventories for fuel burned;
- The cost of fuel burned;
- Net gains or losses resulting from sales of fuel or other fuel-related costs components; and
- The monthly fuel report for the last month in the test period and information required by Rule R8-52 which has not already been filed.

Commission Rule R8-52 requires electric utilities to file a Monthly Fuel Report that includes:

[16] "Each electric public utility, at a minimum, shall submit to the Commission for the purposes of investigation and hearing the information and data in the form and detail as set forth below:"

- Details of cost of fuel burned;
- Details of cost of fuel transportation;
- Details of fuel consumption and inventories; and
- Details of net gains or losses resulting from sales of fuel or other fuel-related costs components.

Q. Did DEC provide the required information with its application?

A. No. The main source of natural gas supply and cost information in the DEC filings is the "Fuel and Fuel Related Cost Report," which shows gas use and the total allocated gas supply cost by plant, by month. The report does not break out gas purchase costs from gas transportation costs, or show any difference between the costs of natural gas purchased and the costs of natural gas burned.

Q. What other natural gas information is missing from the DEC reports?

A. DEC did not provide "details of cost of fuel transportation" or "inventories of fuel burned." This would include information describing the natural gas transportation and storage services under contract, the fixed and variable costs paid for gas transportation and storage, gas storage balances, and how costs were allocated between DEC and DEP.

DEC also failed to provide "details of net gains or losses resulting from sales of fuel or fuel-related cost components." This would include the total revenues and net margins from sales of natural gas sale, and revenue from gas transportation capacity release.

Q. What additional information should DEC include with the annual fuel adjustment application?

A. DEC has the obligation to show that test period natural gas supply costs were reasonable and prudently incurred. In particular, DEC must demonstrate that the gas supply resources under contract were necessary to obtain a reliable supply fuel for electricity generation at a reasonable cost, and that gas supply resources were prudently managed to reduce the costs charged to electricity customers. To make this demonstration, DEC should augment the annual fuel adjustment application to include the following information:

1. DEC should include a table showing the sources and uses of natural gas for each month. "Sources" would include total gas purchased and gas withdrawn from storage. "Uses" would include gas retained by transporters, gas injected into storage, gas used for power generation, and third-party sales. This information will allow the Commission, the Public Staff, and intervenors to see how DEC procured and managed natural gas supplies during the test period.

2. DEC should provide a table listing all firm transportation and storage contracts, both long-term and short term, held by DEC or DEP that were in effect during the test period. For each transportation agreement, DEC should identify the contract holder, the transporter, contract number, rate schedule, contract quantity, daily quantity entitlement at each receipt point, daily quantity entitlement at each delivery point, contract start date, contract expiration date. This will identify the natural gas supply resources that are

currently available, and the duration of existing commitments to pipeline and storage services.

3. DEC should report the reservation charges paid for firm transportation and storage services, by month. This information is needed to quantify DEC customers' exposure to fixed natural gas supply costs.

4. DEC should report the sales quantity, revenue and margin from third-party sales, and the revenue from the capacity release and AMA transactions. This will show the extent to which DEC was able to offset fixed transportation and storage costs using capacity optimization transactions.

5. The testimony supporting the fuel cost adjustment request should include a narrative identifying the changes to natural gas supply resource commitments that occurred during the test period, or are expected to occur during the billing period. This testimony should explain how decisions to enter into new long-term contracts for firm transportation or storage service, or extend the term of an existing agreements (including evergreen contracts), will benefit customers.

Q. Does the fact that the DEC and DEP natural gas supply assets are managed on a combined basis affect how this information should be reported?

A. Yes. Natural gas quantities and costs should be provided on a combined basis, with worksheets showing how quantities and costs are allocated. Because DEC uses the gas supply resources under contract to DEC and DEP to meet the fuel requirements for all plants, the current reporting, which only presents gas use and total allocated gas supply costs for DEC-owned plants, does not demonstrate that these gas supply resources were actually needed, or show whether DEC is prudently managing these assets to reduce the costs charged to customers.

Q. What other information should DEC be prepared to provide, if requested?

A. DEC should be prepared to provide daily gas use for each DEC and DEP plant.[17] To assess the need for firm transportation capacity to supply DEC and DEP plants, it is important to see both average and peak daily use, and when during year gas use is highest. Because the value of firm gas delivery is likely to be higher for a baseload generating plant without alternate fuel capability, and lower for a dual-fueled peaking plant, it is important to see which plants are using gas each day. DEC should also be prepared to provide the daily scheduled quantities for each firm interstate transportation agreement to show how these resources are being utilized.

Q. Does this complete your testimony?

A. Yes, it does.

[17] Sierra Club Data Request 1-11 asked for the maximum daily gas consumption for each plant over the test period. DEC objected on the grounds that the information "is not readily available and production of the requested information would be unduly burdensome." Because natural gas transporters measure the gas delivered at each meter, and electricity generators keep track of fuel use at their facilities, DEC should be expected to have ready access to daily gas consumption data for each of its plants.

CHAIR MITCHELL: All right. Any additional matters for the Commission's consideration before we -- before we close?

MS. DOWNEY: Chair Mitchell?

CHAIR MITCHELL: Yes, ma'am, Ms. Downey. I'm sorry. I forgot to allow you to make your motion. Thank you for bringing it to my attention.

MS. DOWNEY: Generally, Chair Mitchell, we would move that the affidavit of Jenny Li and the testimony of Dustin Metz, along with their indexes and exhibits be entered into the record.

CHAIR MITCHELL: All right. Hearing no objections, Ms. Downey, to your motion, it shall be allowed. Testimony shall be admitted. Exhibits shall be marked as prefiled.

(Metz Exhibit 1 was admitted into evidence.)

(Whereupon, the prefiled direct testimony of Dustin R. Metz and Affidavit and Appendix of Jenny X. Li were copied into the record as if given orally from the stand.)

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	)))))	TESTIMONY OF DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

Testimony of Dustin R. Metz

On Behalf of the Public Staff

North Carolina Utilities Commission

May 15, 2020

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff representing the using and consuming public.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are outlined in detail in Appendix A of my testimony.

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

A. The purpose of my testimony is to present the results of the Public Staff's investigation and recommendations regarding the proposed fuel and fuel-related cost factors for the residential, general service/lighting, and industrial customers of Duke Energy Carolinas, LLC (DEC or the Company), as set forth in the Company's February 25, 2020, application and testimony and May 7, 2020 supplemental testimony.

Q. WHAT ARE THE TEST AND BILLING PERIODS FOR THIS PROCEEDING?

A. For this proceeding, the test period is January 1, 2019, through December 31, 2019, and the billing period is September 1, 2020, through August 31, 2021.

Q. PLEASE DESCRIBE THE SCOPE OF THE PUBLIC STAFF'S INVESTIGATION.

A. The Public Staff's investigation included a review of the Company's test period and projected fuel and fuel-related costs and also the following: (1) the Company's application, testimony, and supplemental testimony and responses to Public Staff data requests; (2) documents related to the performance of the Company's baseload power plants, including the specific performance of the Company's nuclear facilities; (3) the Company's purchased power transactions; (4) the cost of renewables and associated fuel prices; and (5) the Company's coal, natural gas, nuclear, and reagent procurement practices and contracts.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR INVESTIGATION AND YOUR RECOMMENDATIONS.

- The Company has correctly calculated the proposed fuel and fuel-related cost factors in this proceeding.
- For the test year, the Company achieved the capacity factor standard in Commission Rule R8-55(k), and calculated the proposed base system average fuel factor for the billing period appropriately.
- There are impacts to future fuel filings related to the Clemson Combined Heat and Power (Clemson CHP) project that is a contested issue in the pending DEC general rate case in Docket No. E-7, Sub 1214.

Q. DO YOU AGREE WITH THE COMPANY'S DETERMINATION AND CALCULATION OF THE PROPOSED BASE SYSTEM AVERAGE FUEL FACTOR?

A. I agree with the Company's determination and calculation of the proposed base system average fuel factor, EMF (experience modification factor) and EMF interest for the billing period, except for the impact of the steam revenue associated with the Clemson CHP project on projected fuel rates, as discussed later in my testimony.

Q. DID THE COMPANY MEET THE STANDARDS OF COMMISSION RULE R8-55(K) FOR THE TEST YEAR?

A. For the test year, the Company met the standards of Commission Rule R8-55(k) with an actual system-wide nuclear capacity factor that exceeded the NERC (North American Electric Reliability Corporation) weighted average nuclear capacity factor. Additionally, the Company's two-year simple average of its system-wide nuclear capacity factor exceeded the NERC weighted average nuclear capacity factor.

Q. DID THE PUBLIC STAFF REVIEW THE BILLING PERIOD OR PROJECTED FUEL AND FUEL-RELATED COSTS AS SET FORTH BY THE COMPANY IN THIS FILING?

A. Yes. The projected fuel and reagent costs are reasonable and were calculated appropriately. The projected cost of fuel and fuel-related costs are affected by minor projected fluctuations in nuclear fuel, coal, and natural gas costs. DEC's proposed fuel and fuel-related costs are based on a 94.39% system nuclear capacity factor, which is what the Company anticipates for the billing period.[1]

Q. PLEASE PROVIDE THE PROPOSED FUEL AND FUEL-RELATED COST FACTORS.

A. Metz Exhibit No. 1 shows the Proposed Fuel and Fuel-Related Cost Factors. The Public Staff recommends approval of the fuel components and total fuel factors (excluding the regulatory fee), shown in Exhibit No. 1, Table 1, effective for the twelve months beginning September 1, 2020.

Public Staff witness Li discusses the Public Staff's review of the test period EMF and EMF interest in her affidavit, and I have incorporated her recommendations in Metz Exhibit No. 1.

Q. EARLIER IN YOUR TESTIMONY, YOU DESCRIBE THE IMPLICATIONS OF THE CLEMSON CHP PROJECT ON FUTURE FILINGS. PLEASE DISCUSS.

A. Prior to the Company filing its application in this docket, I filed supplemental testimony in DEC's pending general rate case regarding the Clemson CHP project. In my rate case supplemental testimony on this matter, I recommended that the Clemson CHP

[1] The Company's actual system nuclear capacity factor for the test year was 97.1%. In comparison, the most recent North American Electric Reliability Council (NERC) five-year average weighted for the size and type of reactors in DEC's nuclear fleet was 91.6% during the test period.

project be removed from North Carolina retail rate base. The Company sells process steam to Clemson University from the Clemson CHP, and the revenues received from the steam sales will be an offset to fuel costs in DEC's annual fuel proceedings. Since this issue is still pending before the Commission in the general rate case, the projected billing period revenues from the steam sales are included in this fuel proceeding. However, it is possible that in future annual fuel cases, the steam revenues will need to be adjusted or removed from North Carolina retail cost of service as an offset to fuel-related costs, depending on the Commission's final decision in the Sub 1214 general rate case.

Q. HAVE YOU REVIEWED THE COMPANY'S CALCULATIONS FOR THE CLEMSON STEAM SALE REVENUES INCLUDED IN THE BILLING PERIOD IN THIS CASE?

A. Yes.

Q. ARE THE STEAM REVENUES IN THIS CASE AN ESTIMATE FOR THE BILLING PERIOD?

A. Yes. The actual steam revenues will be trued up in future.

Q. ARE THE COMPANY'S CALCULATIONS FOR THE STEAM SALES REVENUES CONSISTENT WITH THE STEAM CONTRACT PROVISIONS?

A. Yes.

Q. ARE THE STEAM REVENUES BASED ON THE ACTUAL DELIVERED PRICE OF NATURAL GAS TO THE CLEMSON CHP?

A. No, they are not. Under the Clemson CHP steam contract, the steam revenues are based on the NYMEX Henry Hub (HH) price of natural gas, along with a tiered multiplier based on the annual amount of steam purchased by Clemson University. I discuss the steam contract in more detail in my supplemental testimony in the rate case.

Q. WHAT CHANGES TO THE STEAM SALES REVENUES ARE YOU PROPOSING IN THIS PROCEEDING?

A. I am not proposing any changes at this time. However, depending on the Commission's determination in the pending general rate case regarding whether the cost of Clemson CHP Project should be included in North Carolina retail rates, there may be required adjustments in future annual fuel rider proceedings.

Q. PLEASE EXPLAIN WHAT FUTURE ADJUSTMENTS YOU BELIEVE MAY BE APPROPRIATE DEPENDING ON HOW THE COMMISSION TREATS THE CLEMSON CHP PROJECT IN THE PENDING GENERAL RATE CASE.

A. If the Commission finds that the capital costs of the Clemson CHP Project are reasonable and prudent and should be recovered from

North Carolina retail customers, a full allocable portion of the associated fuel costs and steam revenues would flow through the annual fuel rider. If, however, the Commission excludes the capital costs of the Clemson CHP project from recovery, the associated steam revenues should be removed from the annual fuel rider, beginning with the EMF in the next fuel proceeding.

It is also possible that the Commission's ruling in the rate case addresses the reasonableness and prudence of the capital costs, but not the steam revenue from the steam sale contract. In that case, in the next fuel proceeding, the Public Staff would likely challenge the amount of steam revenue in the steam sale contract and recommend that revenues be imputed to cover the full capital costs of the Clemson CHP project.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, this concludes my testimony.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion and an additional six years of employment with an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1228

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC	)	AFFIDAVIT
Pursuant to N.C.G.S. § 62-133.2 and	)	OF
Commission Rule R8-55 Relating to Fuel and	)	JENNY X. LI
Fuel-Related Charge Adjustments for Electric	)	
Utilities	)	

STATE OF NORTH CAROLINA

COUNTY OF WAKE

I, Jenny X. Li, first being duly sworn, do depose and say:

I am a Staff Accountant with the Electric Section of the Accounting Division of the Public Staff - North Carolina Utilities Commission. A summary of my education and experience is attached to this affidavit as Appendix A.

The purpose of my affidavit is to present the results of the Public Staff's investigation of the Experience Modification Factor (EMF) riders proposed by Duke Energy Carolinas, LLC (DEC or the Company) in this proceeding. The EMF riders are utilized to "true-up," by customer class, the recovery of fuel and fuel-related costs incurred during the test year. DEC's test year in this fuel proceeding is the twelve months ended December 31, 2019.

In its application, filed on February 26, 2020, DEC proposed EMF increment riders in cents per kilowatt-hour (kWh), excluding the North Carolina regulatory fee, for each North Carolina retail customer class, as follows:

Residential	0.1574 cents per kWh
General Service/Lighting	0.1510 cents per kWh
Industrial	0.3067 cents per kWh

On May 7, 2020, DEC filed the Supplemental Testimony of Kimberly D. McGee with Revised McGee Exhibits and supporting workpapers. Witness McGee's supplemental testimony and revised exhibits reflect the impact of two updates to numbers presented in witness McGee's direct exhibits and workpapers. They are as follows:

(1) To update the EMF increment to incorporate the fuel and fuel-related cost recovery balance for January through March 2020, pursuant to Commission Rule R8-55(d)(3). The reported over-recovery included in the update, although included in this proceeding, would be reviewed as part of next year's fuel and fuel-related cost proceeding; and,

(2) To include a revised projected net(gain)/loss on the sale of steam which is included in estimated system fuel and fuel-related costs for the billing period.

Revised McGee Exhibit 1 included in witness McGee's supplemental testimony sets forth the Company's revised proposed EMF increment riders in cents per kilowatt-hour (kWh), excluding the North Carolina regulatory fee, for each North Carolina retail customer class, as follows:

Residential	0.0364 cents per kWh
General Service/Lighting	0.0666 cents per kWh

Industrial	0.2658 cents per kWh

In witness McGee's Revised Exhibits filed on May 7, 2020, DEC's proposed revised under-recovery of fuel for each of the North Carolina retail customer classes is as follows:

Residential	$ 8,172,161
General Service/Lighting	$15,770,030
Industrial	$33,198,354

The revised riders were calculated by dividing the fuel cost under-recoveries by DEC's normalized test year N.C. retail sales of 22,444,481 megawatt-hours (MWh) for the residential class, 23,688,550 MWh for the general service/lighting class, and 12,489,508 MWh for the industrial class.

The Public Staff's investigation included procedures intended to evaluate whether the Company properly determined its per books fuel and fuel-related costs and revenues during the test period. These procedures included a review of the Company's filing, prior Commission orders, the Monthly Fuel Reports filed by the Company with the Commission, and other Company data provided to the Public Staff. The Public Staff also reviewed certain specific types of expenditures impacting the Company's test year fuel and fuel-related costs, including reagents (limestone, ammonia, urea, etc.), renewable energy, and purchased power, as well as reviews of source documentation of fuel and fuel-related costs for certain selected Company generation resources. Performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests, and several telephone conferences with Company representatives.

As a result of the Public Staff's investigation, I am recommending that DEC's EMF riders for each customer class be based on net fuel and fuel-related cost under-recoveries of $8,172,161 for the residential class, $15,770,030 for the general service/lighting class, and $33,198,354 for the industrial class, and normalized North Carolina retail sales of 22,444,481 MWh for the residential class, 23,688,550 MWh for the general service/lighting class, and 12,489,508 MWh for the industrial class, as proposed by the Company. These amounts produce EMF increment riders for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	0.0364 cents per kWh
General Service/Lighting	0.0666 cents per kWh
Industrial	0.2658 cents per kWh

I have provided these amounts to Public Staff witness Dustin Metz for incorporation into his recommended final fuel factor.

This completes my affidavit.

Jenny Li

Jenny X. Li

Sworn to and subscribed before me
this the 15th day of May, 2020.

SHANNON DESOUZA
Notary Public
Wake
County
My Comm. Exp.
1.5.2025
NORTH CAROLINA

Shannon DeSouza
Notary Public

My Commission Expires: 1.5.2025

APPENDIX A

Jenny X. Li

I graduated from North Carolina State University with a Bachelor of Science degree in Accounting.

I joined the Public Staff Accounting Division in August 2016 as a Staff Accountant. I am responsible for the performance of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings.

Since joining the Public Staff, I have filed affidavits in Duke Energy Carolinas, LLC (DEC) fuel rider, Duke Energy Progress, LLC (DEP) fuel rider, Dominion Energy North Carolina REPS rider. I have also assisted on several electric cases and performed reviews in Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) rate cases. I have also performed reviews of DEC's Existing DSM Program Rider and BPM/NFPTP Rider; Western Carolina University's PPA Rider and New River Light and Power Company's PPA Factor.

Prior to joining the Public Staff, I was employed by MDU Enterprises Inc. and Neusoft America Inc. My duties there varied from examining various financial statements to supervising accounting and assisting external audits.

CHAIR MITCHELL: All right. Any additional matters from you, Ms. Downey, or from any other party?

MR. JIRAK: Nothing from Duke Energy Carolinas. Thank you, Chair Mitchell.

MS. DOWNEY: Nothing from the Public Staff.

CHAIR MITCHELL: Okay. As is typical, the Commission will accept post-hearing briefs and proposed orders 30 days from the notice of the transcript, and with that, hearing nothing further, we will be adjourned and go off the record. Thank you very much.

(Hearing concluded at 1:10 p.m.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly sworn; that the testimony of said witnesses were taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 19th day of June, 2020.

JOANN BUNZE, RPR

Notary Public #200707300112