PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, June 11, 2019

TIME: 9:30 a.m. - 9:40 a.m.

DOCKET NO: E-7, Sub 1190

BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

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

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T A B L E O F C O N T E N T S

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL: Good morning. Let's come to order, please, and go on the record. I am Commissioner Charlotte Mitchell, Chair of the Utilities Commission. With me this morning are Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, and Daniel G. Clodfelter.

I now call for hearing Docket Number E-7, Sub 1190, which is the Application by Duke Energy Carolinas, LLC, Pursuant to G.S. § 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Charge 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 that the fuel charge adjustment proceeding for Duke Energy Carolinas, hereafter I will refer to as DEC, will be held the first Tuesday of June of each year. The Rule further provides that DEC shall file direct testimony and exhibits in support of fuel charge adjustments and publish public notice prior to the hearing.

On February 26, 2019, DEC filed its

Application to adjust the fuel and fuel-related cost component of its electric rates, along with its supporting testimony and exhibits.

On March 8, 2019, the Commission issued its Order Scheduling the Hearing, Requiring the Filing of Testimony and Establishing Discovery Guidelines and Requiring Public Notice.

On March 18, 2019, the Commission issued an Order rescheduling this hearing from June 4th to June 11, 2019, commencing at 9:30 a.m.

On April 30, 2019, DEC filed supplemental testimony and exhibits.

On May 2nd, the Commission issued an Order requiring DEC to publish a second public notice regarding changes to DEC's Application made in DEC's supplemental testimony and exhibits, and to file Affidavits of Publication.

Petitions to intervene in this docket were timely filed by Carolina Industrial Group for Fair Utility Rates, III (CIGFUR III); Carolina Utility Customers Association, Inc. (CUCA); North Carolina Sustainable Energy Association (NCSEA); and the Sierra Club. These Petitions to Intervene were allowed by separate Orders of the Commission.

The intervention and participation by the Public Staff is recognized pursuant to G.S. § 62-15.

On May 14, 2019, DEC filed its Affidavits of Publication regarding the additional public notice. DEC stated that it would file the Affidavits of Publication for the second public notice when those affidavits were received from the newspapers.

On May 15th, DEC filed second supplemental testimony.

On May 20, 2019, the Public Staff filed the affidavits of Jay Lucas and Jenny Li.

On June 3rd, DEC filed a Motion requesting that all DEC and Public Staff witnesses be excused from attending this hearing and that the prefiled testimony, exhibits and affidavits of the respective witnesses and affiants be received into evidence and made a part of the record in this matter.

DEC filed its Affidavit of Publication regarding the second public notice on June 4, 2019.

On June 6, 2019, the Sierra Club filed a response to DEC's Motion to Excuse Witnesses. And on June 7, 2019, the Commission issued an Order Excusing all Witnesses from Attending the Hearing.

Pursuant to State Law, I remind all members

of the Commission of our duty to avoid conflicts of interest, and inquire at this time whether any member has a known conflict of interest with regard to the matter before us this morning?

(No response)

Please let the record reflect that no such conflicts were identified, so we will proceed with the hearing.

I now call upon counsel for the parties to announce their appearances, beginning with the Applicant.

MR. KAYLOR: Thank you, Madam Chair. Robert Kaylor appearing on behalf of Duke Energy Carolinas.

MR. JIRAK: Jack Jirak on behalf of Duke Energy Carolinas.

CHAIR MITCHELL: Good morning.

MR. SMITH: Ben Smith here on behalf of the North Carolina Sustainable Energy Association.

MS. THOMPSON: Good morning. Madam Chair, Members of the Commission, Gudrun Thompson appearing on behalf of the Sierra Club.

MR. PAGE: Good morning. Madam Chairman, Commissioners, I'm Bob Page representing Carolina Utility Customers Association.

MS. HICKS: Good morning. Warren Hicks on behalf of Carolina Industrial Group for Fair Utility Rates.

MS. DOWNEY: Good morning. Dianna Downey on behalf of the Public Staff representing the Using and Consuming Public.

CHAIR MITCHELL: Good morning.

Are there any preliminary matters before we begin?

MR. JIRAK: None at this time.

CHAIR MITCHELL: Ms. Downey?

MS. DOWNEY: No.

CHAIR MITCHELL: Okay. Has the Public Staff identified any public witnesses who wish to testify in this matter?

MS. DOWNEY: No, I have not.

CHAIR MITCHELL: And since -- is there anyone in the room wishing to testify as a public witnesses in this proceeding?

(No response)

Having -- no one having appeared we'll go ahead and move forward with the Applicant.

MR. JIRAK: Thank you, Chair Mitchell. As you noted, the Commission's June 7, 2019 Order excused

the Company's witnesses from appearing at this time. On behalf of Duke Energy Carolina, I would respectfully move that the prefiled direct testimony and exhibits of Duke Energy Carolinas' witnesses be received as evidence in the record as if given orally via the stand, that the prefiled exhibits of the witnesses also be moved into evidence as premarked and prefiled, and I'll briefly identify that testimony for your benefit.

The DEC direct testimony exhibits that are being moved into evidence were filed on February 26, 2019, and consist of -- and were filed on behalf of Kimberly McGee, Eric S. Grant, Regis Repko, Kevin Houston and Stephen Capps. DEC's supplemental testimony and exhibits that will be moved into evidence were filed on April 30, 2019, and were filed on behalf of Kimberly McGee. And, finally, DEC's second supplemental testimony and exhibits that are also being moved into evidence this morning were filed on May 15, 2019, and were filed on behalf of Kimberly McGee. And, finally, in addition, we'd like to move the Application that these Duke witnesses and exhibits support into the record as well.

CHAIR MITCHELL: Thank you very much,

Mr. Jirak. Without objection, that motion will be allowed.

MR. JIRAK: Thank you.

(WHEREUPON, Application of Duke Energy Carolinas, LLC, is admitted into evidence.)

(WHEREUPON, McGee Exhibits 1 - 6 and McGee Workpapers 1 - 14 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of KIMBERLY D. McGEE is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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	)	

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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 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, 2018 ("test period"), and the billing period is September 1, 2019 through August 31, 2020 ("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 92.95% proposed nuclear capacity factor and projected megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 92.95% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 90.21% 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 2018 Monthly Fuel Reports.

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

2) December 2018 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 1.9051¢, 2.0161¢, and 2.0789¢ per kWh, respectively, to be reflected in rates during the billing period. The factors DEC proposes in this proceeding incorporate a 92.95% nuclear capacity factor as testified to by Company witness Capps, projected fossil fuel costs as testified to by Company witness Grant, 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	1.7943	1.9529	1.9313	1.8901
EMF Increment (Decrement)	0.1108	0.0632	0.1476	0.0994
Net Fuel and Fuel Related Costs Factors	1.9051	2.0161	2.0789	1.9895

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 1.01% increase 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	1.9051	2.0161	2.0789	1.9895
Existing Total Fuel Factor	1.7983	1.9382	2.0233	1.9059

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

A. The increase in the proposed net fuel and fuel-related costs factors for all customer classes is primarily driven by an increase in coal commodity prices. An increase in gas generation due to lower gas prices partially offsets higher coal-related fuel cost. In addition, the under-collection of $57.7 million for the current test period is lower than the under-collection of $73.3 million included in setting fuel rates during the 2018 annual fuel proceeding, thus reducing the total rate increase.

Company witness Houston explains that the billing period price of 0.6115¢ per kWh for nuclear fuel is lower than experienced during the test period and lower than the prices reflected in current rates. As discussed by Company witness Grant, the proposed fuel and fuel-related costs factors include an average delivered cost for coal for the billing period of $66.80 per ton, which is 13% lower than the average delivered cost of coal per ton during the test period and lower than prices reflected in current rates. In addition, Company witness Grant notes a decrease in natural gas prices as evidenced by the Henry Hub[1] forward price of $2.75 per Million British Thermal Units ("MMBtu") used in the proposed fuel rates, compared to $3.09 per MMBtu in the test period.

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

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 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 92.95%, and provides the forecasted MWh sales for the billing period on which system generation and costs are based.

Schedule 2 also uses the proposed capacity factor of 92.95% 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 90.21%. This capacity factor is based on the 2013 through 2017 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

increased 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 90.21% NERC nuclear capacity factor compared to the proposed 92.95% 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 $24.4 million, $14.8 million, and $18.4 million, respectively. There were two adjustments included in the calculation of the under-recovery balance at December 31, 2018. The first adjustment relates to the months of January 2018 through March 2018 which were included in the fuel rate approved in the last fuel and fuel-related cost recovery proceeding and are included for Commission review in the current proceeding. The Company has excluded the (over)/under recovery for the months of January 2018 through March 2018 when computing the current EMF factors. Secondly, included in the test period (over)/under calculation is the under collection related to the coal inventory rider established in Ordering Paragraph 27 of the Commission's June 22, 2018 *Order Accepting Stipulation, Deciding Contested Issue and Requiring Revenue*

Reduction in Docket No. E-7, Sub 1146. The coal inventory rider was terminated from rates effective for service on and after December 1, 2018. DEC is not recovering any additional coal inventory rider costs beyond October 2018 when the termination requirements were met, but due to the timing of receiving final coal inventory reports, the rider was terminated at the end of November 2018. All amounts collected after October 2018 through January 2019 have been used to reduce the under-collected balance as of the end of October 2018. Interest has been accrued on the under-collected balance through August 2019.

Including these two adjustments results in under-collected EMF increments of 0.1108¢, 0.0632¢ and 0.1476¢ per kWh, respectively, for the residential, general service/lighting, and industrial customer classes based on normalized test period sales by customer class.

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 1.8969¢ 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 Grant 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 2018 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1163.

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 1.05% was calculated by dividing the fuel and fuel-related cost increase of $48,252,245 for North Carolina retail by the normalized annual North Carolina retail revenues

at current rates of $4,609,002,994. The cost increase of $48,252,245 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 1.05%. 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.

(WHEREUPON, Grant Exhibits 1 and 2 and Confidential Grant Exhibit 3 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of ERIC S. GRANT is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Eric S. Grant. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

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

Carolina.

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

A. Yes. I filed testimony in DEC's 2018 North Carolina fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1163 and in DEP's 2018 North Carolina fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1173.

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, 2018 through December 31, 2018 ("test period") versus the period January 1, 2017 through December 31, 2017 ("prior test period"), and describe changes projected for the billing period of September 1, 2019 through August, 31 2020 ("billing period").

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

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

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 Grant 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 $78.71 per ton, compared to $74.90 per ton in the prior test period, representing an increase of approximately 5%. This includes an average transportation cost of $29.58 per ton in the test period, compared to $26.46 per ton in the prior test period, representing an increase of approximately 12%. The Company's average

price of gas purchased for the test period was $3.84 per Million British Thermal Units ("MMBtu"), compared to $3.65 per MMBtu in the prior test period, representing an increase of approximately 5%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEC's coal burn for the test period was 8.7 million tons, compared to a coal burn of 9.7 million tons in the prior test period, representing a decrease of 10%. The Company's natural gas burn for the test period was 128.8 MMBtu, compared to a gas burn of 80.8 MMBtu in the prior test period, representing an increase of approximately 59%. The net increase in DEC's overall natural gas burn was primarly driven by the addition of the new Lee combined cycle facility, which became commercially available in April 2018. An additional contributing factor to changes in coal and natural gas burns were commodity prices.

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

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

With respect to natural gas, the nation's natural gas supply has grown

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

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

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

A. DEC's current coal burn projection for the billing period is 6.5 million tons, compared to 8.7 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 $66.80 per ton for the billing period compared to $77.13 per ton in the test period. The lower projected cost is due, in part, to newly

negotiated rail transportation contracts that go into effect in early spring 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 147.2 MMBtu, which is an increase from the 128.8 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 Cliffside, Belews Creek, and Marshall Units 3 & 4 as a result of the dual fuel conversions being commercial available over the course of the billing period. The current average forward Henry Hub price for the billing period is $2.75 per MMBtu, compared to $3.09 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. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

(WHEREUPON, the prefiled direct testimony of REGIS T. REPKO is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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	)))))	**DIRECT TESTIMONY OF REGIS REPKO FOR DUKE ENERGY CAROLINAS, LLC**

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. I also have completed the Institute of Nuclear Power Operations (INPO) Senior Nuclear Plant Manager Course. 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 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 2018 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, 2018 through December 31, 2018 (the "test period"), (3) provide information on significant Fossil/Hydro/Solar outages that occurred during the test period, and (4) provide information concerning environmental compliance efforts.

Q. PLEASE DESCRIBE DEC'S FOSSIL/HYDRO/SOLAR GENERATION PORTFOLIO.

A. The Company's Fossil/Hydro/Solar generation portfolio consists of approximately 14,991 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	6,764 MWs
Steam Natural Gas -	170 MWs
Hydro -	3,245 MWs
Combustion Turbines -	2,665 MWs
Combined Cycle Turbines -	2,116 MWs

Solar - 31 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 – W.S. 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 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 72 units providing approximately 1,104 MWs of capacity. The 31 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 21 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 2017 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. DEC added Lee CC in April 2018, which added 786 MWs of capacity. The Hydro Fleet retired the Rocky Creek Station, units at Great Falls in May 2018 and two units at Ninety-Nine Islands in December 2018. Cliffside Station was upgraded to allow for dual fuel operation, allowing utilization of coal and natural gas. DEC completed the Woodleaf solar facility in December 2018. This facility has 6 MWs of nameplate capacity which provide 2 MWs of relative summer dependable capacity.

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 9,468 Btu/kWh. Based on operating performance data for 2017 that was published in the June 2018 issue of *Power Engineering* magazine, DEC's Rogers Energy Complex ("Cliffside"), Belews Creek Steam Station ("Belews Creek"), and Marshall Steam Station ("Marshall") ranked as the second, fourth, and eighth most efficient coal-fired generating stations in the nation with heat rates of 9,055 Btu/kWh, 9,167 Btu/kWh, and 9,495 Btu/kWh, respectively. These results compare favorably to the average heat rate of 10,476 Btu/kWh for North American coal generators, also reported in the above noted magazine. For the test period, the Marshall units provided 37% of coal-fired generation for DEC, with the Belews Creek units providing 35% and Cliffside providing 24%.

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 101.8 million MW hours ("MWhs") for the test period. The Fossil/Hydro/Solar fleet provided 41.8 million MWhs, or approximately 41% of the total generation. As a percentage of the total generation, 22% was produced from coal-fired stations and approximately 13% from CC operations, 3% from CTs, 2% from hydro facilities, and .13% 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 the 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.

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

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 2013 through 2017, and is categorized by generator type. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating. The data in the chart reflects DEC results compared to the NERC five-year comparisons.

Generator Type	Measure	Review Period	2013-2017	Nbr of Units
		DEC Operational Results	NERC Average	
Coal-Fired Test Period	EAF	79.5%	78.4%	752
	NCF	38.3%	56.4%	
	EFOR	7.5%	8.7%	
Coal-Fired Summer Peak	EAF	95.8%	n/a	n/a
Total CC Average	EAF	86.2%	85.0%	338
	NCF	76.7%	52.7%	
	EFOR	3.32%	5.3%	
Total CT Average	EAF	83.3%	87.8%	776
	SR	99.4%	98.1%	
Hydro	EAF	76.3%	80.4%	1,113

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

Bad Creek hydro completed a major outage in Spring 2018, which included spherical valve overhauls and inspections of the intake and penstock to prepare for the Bad Creek uprate project, which will begin in Fall 2019. Lincoln

CT Unit 1 and Unit 2 completed an outage in Spring 2018 to upgrade the turbine control system. The CC fleet performed planned outages at Dan River CC and Buck CC in Spring 2018. The primary purpose of the Dan River CC outage was to perform a CT borescope inspection and a heat recovery steam generator inspection. The primary purpose of the Buck CC outage was to perform a borescope inspection on each combustion turbine.

In Fall 2018, Belews Creek Unit 2 preformed a boiler outage. The primary purpose of the outage was to replace the secondary superheater in the boiler and rewind the LP generator. Marshall Unit 2 completed an outage in Fall 2018. The primary purpose of this outage was to replace the HP and LP turbine rotors. Cliffside Unit 5 and Unit 6 completed an outage for the dual fuel conversion to allow the units to burn coal and natural gas. Lincoln CT Units 3-8 completed an outage in Fall 2018 to upgrade the turbine control systems.

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.

(WHEREUPON, the prefiled direct testimony of KEVIN Y. HOUSTON is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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 serve 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 1163.

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, 2018 through December 31, 2018 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2019 through August 31, 2020 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 $45.06 per pound for uranium concentrates during the test period, representing an increase of 15% per pound 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 2% to $118.62 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 – 16% 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 44% and 36%, respectively.

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

A. Prices in the uranium concentrate markets remain relatively low with the continued lack of demand due to the March 2011 event at Fukushima. Industry consultants, however, believe market prices 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 continued to decline primarily due to reduced demand and increased supplier inventories following the Fukushima event. Additionally, the transition by enrichment suppliers from gaseous diffusion technology to the more cost efficient gas centrifuge technology was a market driver.

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 increased 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 decrease from 0.6149 cents per kWh incurred in the test period, to approximately 0.6115 cents per kWh in the billing period. This change reflects the discharge of fuel with a higher cost basis from the reactors and its replacement with fuel procured under new contracts negotiated in lower markets.

Q. WHAT STEPS IS 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.

(WHEREUPON, Confidential Capps Exhibit 1 is marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of STEPHEN D. CAPPS is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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 31 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.

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, 2018 through December 31, 2018 ("test period"). I provide information about refueling outages for the test 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, 2019 through August 31, 2020 ("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 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.

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

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 59% of the total power generated by DEC. During 2018, DEC's seven nuclear units achieved the third highest annual net generation in the Company's history, falling just below record output achieved in 2016 and 2017 despite the fact that there was one additional refueling outage in 2018 as compared to the two prior years. The average capacity factor in 2018 for the Company's nuclear fleet was 95.29%, thereby marking the 19th consecutive year in which DEC's nuclear fleet achieved a system capacity factor

exceeding 90%. All five of the Company's refueling outages in 2018 were completed within the scheduled allocation durations. McGuire Unit 1 established a new net generation record during 2018, and McGuire Unit 2 operated continuously during the operating cycle leading up to the September 2018 refueling outage. Catawba Unit 1 operated continuously during the cycle leading into the November 2018 refueling outage, and established a new record for the highest net generation for 9 months during the year. Catawba Unit 2 also achieved a continuous cycle run leading into that unit's March 2018 refueling outage, which represented the second shortest refueling outage for the unit. During the peak summer demand, the Oconee station achieved the highest 3rd quarter output in the station's history, and, over the course of entire year, recorded the third best annual generation performance.

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 90.21% for the period 2013 through 2017 for comparable units (pressurized water reactors on a capacity-rated basis with capacity ratings at and above 800 MWs). The Company's 2018 capacity factor of 95.29% and 2-year average[2] of 95.58% both exceed the NERC average of 90.21%.

[2] This represents the simple average for the current test period and prior test period of 12 months ended December 2016 for the DEC nuclear fleet.

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 2018 from the Electric Utility Cost Group, all three of DEC's nuclear plants rank in the top quartile in total operating cost among the 60 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 39 million MWhs of additional, carbon-free generation over the past 19 years (as compared with production at a capacity factor of 90%), which is equivalent to an additional 8 months of output from DEC's nuclear fleet (based on DEC's average annual generation for the same 19-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 or less becomes the goal for that task in each subsequent outage. Those individual aspirational goals are incorporated into an overall outage schedule. The Company then aggressively works to meet, and measures itself against, that aspirational schedule. To minimize potential impacts to outage schedules due to unforeseen maintenance requirements, "discovery activities" (walk-downs, inspections, etc.) are scheduled at the earliest opportunities so that any maintenance or repairs identified through those activities can be promptly incorporated into the outage plan.

As noted, the schedule is utilized for measuring outage planning and execution and driving continuous improvement efforts. However, for planning purposes, particularly with the dispatch and system operating center functions, 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 or to defer work is based on numerous factors, including reliability risk assessments, system power demands, and the availability of resources to address the emergent challenge. In general, if an issue poses a credible risk to reliable operations until the next scheduled outage, the issue is repaired prior to returning the unit to service. This approach enhances reliability and results in longer continuous run times and fewer forced outages, thereby reducing fuel costs for customers in the long run. In the event that a unit is forced off-line, every effort is made to safely perform the repair and return the unit to service as quickly as possible.

Q. DOES 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 AND MAINTENANCE AT DEC'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. There were five refueling outages completed during the test period. All five outages were completed within the duration allocation windows, and the combined O&M outage costs for the five refueling outages totaled $143[3] million compared to the combined budget for the five outages of $146.8 million.

The Catawba Unit 2 refueling outage began on March 17, 2018. In addition to refueling, reliability and safety enhancing maintenance was completed. Major pump and motor work included the replacement of the 2A stator coolant

[3] The combined outage cost and budget is inclusive of Catawba's joint owners' share.

pump, 2A condensate booster pump motor, 2B residual heat removal pump and motor, and the 2B2 component cooling pump and motor. Electrical work included installation of a new governor, with slow start capability, on the 2A emergency diesel generator ("EDG"), and rebuild of the 2B EDG battery charger. The first phase of the emergency supplemental power source electrical tie-ins was completed, adding additional emergency power resources and increasing maintenance flexibility on the EDGs. The distributed control system was upgraded and the open phase detection modification was completed on Unit 2. Fifty-three control rod drive mechanism cables and associated connectors were replaced. Repairs were completed on the 2A low pressure turbine rotor and robotic inspections were completed on eight welds associated with four nozzles on the reactor head. After refueling, maintenance, and modifications were completed, the unit returned to service on April 14, 2018, for a total outage duration of 27.9 days compared to a schedule allocation of 30 days. Following restart from the refueling outage, the turbine was disconnected for 6.2 hours to complete turbine overspeed trip testing.

After completing operating cycle 29, Oconee Unit 3 shut down on April 20, 2018 for refueling. In addition to refueling activities, major work included installation of new protective relaying on the main transformer, auxiliary transformer, and generator. Power circuit breaker 30 and numerous molded case breakers were replaced. Main step-up transformer work included the replacement of three high side bushings. Eddy Current testing was completed on all tubes in both steam generators. The 3A2 high pressure injection line thermal sleeve was replaced and preventative maintenance was completed on the 3C low pressure

turbine rotor. After refueling, maintenance, and modifications were completed, the outage successfully completed on May 19, 2018. The outage duration was 28.2 days compared to a schedule allocation of 29 days.

McGuire Unit 2 shut down for refueling on September 15, 2018. In addition to refueling, major pump and motor work included the 2C2 heater drain pump motor replacement, 2A2 component cooling pump motor replacement, 2B chemical and volume control system pump motor replacement, and the rebuild of the 2B nuclear service water pump. Electrical work included replacement of the 2B main step-up transformer, and installation, testing, and tie-in of the emergency supplemental power supply ("ESPS") diesel generators. The ESPS installations provide an additional source of backup power and allow additional flexibility to complete maintenance on the station's emergency diesel generators. The open phase detection modification was also installed. Other work performed included repair of the 2A low pressure turbine #4 bearing, turning gear replacement, and steam generator secondary separator inspections and repair. Insulation was replaced on the reactor vessel head and digital rod position indication head cables and coil stacks were replaced. After refueling, inspections, maintenance, and modifications completed, the unit returned to service on October 13, 2018. The outage completed in 28.5 days compared to a schedule allocation of 29 days.

On October 19, 2018, Oconee Unit 1 was removed from service to begin a refueling outage. In addition to refueling activities, the Unit 1 switchyard power circuit breaker 18, main step-up transformer, and numerous molded case circuit breakers were replaced. The 1B2 reactor coolant pump ("RCP") rotating assembly was replaced and the 1B1 RCP motor bearing was repaired. Eddy

Current testing was completed on all tubes in both steam generators. Turbine work included inspections and maintenance for the 1B low pressure turbine. After refueling, maintenance, testing, and modifications were completed, the unit returned to service on November 14, 2018, for a duration of 25.7 days compared to a schedule allocation of 31.75 days. After the conclusion of the refueling outage, the turbine was disconnected for 1.3 hours for turbine overspeed testing.

The fifth and final refueling outage of the year began on November 17, 2018 when Catawba Unit 1 entered its fall refueling outage. In addition to refueling activities, the station completed inspections, maintenance, and modifications that improved safety margins and strengthened reliability. Major reliability pump and motor work included replacement of the 1A nuclear service water pump and motor, the 1C hotwell pump and motor, and the 1A condensate booster pump motor. Modifications completed included the installation of the open phase detection system and emergency diesel generator governor modifications that added slow start capabilities. Both modifications improve safety margins related to offsite and backup power. Turbine and feedwater work included inspections of the 1B low pressure turbine, the 1A main feedwater pump turbine, and inspections of the 1A auxiliary feedwater pump turbine and jet plug repair. Other significant inspections included Eddy Current testing on the Unit 1 steam generator, control rod guide tube and Alloy 600 auxiliary head adapter encoded inspections. After inspections, maintenance, and modifications completed, the unit returned to service on December 11, 2018. The duration of the outage was 24.5 days compared to a schedule allocation of 28 days.

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 92.95% 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 90.21% for comparable units as reported in the NERC Brochure during the period of 2013 to 2017.

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

A. Yes, it does.

(WHEREUPON, Revised Supplemental McGee Exhibit 1, Supplemental McGee Exhibit 2, Revised Supplemental McGee Exhibits 3 and 4, Supplemental McGee Exhibit 5 and Revised Supplemental McGee Exhibit 6 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled supplemental testimony of KIMBERLY McGEE is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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 26, 2019, I caused to be pre-filed with the Commission my direct testimony and 6 exhibits and 14 supporting workpapers.

Q. YOUR SUPPLEMENTAL TESTIMONY INCLUDES 5 REVISED EXHIBITS AND 3 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 Exhibit 4: MWh Sales, Fuel Revenue, and Fuel and Fuel-Related Expense, as well as System Peak for the test period.

Revised McGee Exhibit 6: December 2018 Monthly Fuel Reports.

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

Revised McGee Workpaper 12: Weather Normalization Adjustment.

Revised McGee Workpaper 13: Customer Growth Adjustment

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

A. The purpose of my testimony is to present the revised rates reflecting the impacts related to six updates to numbers presented in my direct exhibits and workpapers. The first update relates to the wholesale weather normalization adjustment used in the calculation of normalized test period sales shown on Exhibit 2, Schedule 2, Exhibit 3 and Exhibit 4 and is described further below. The second update relates to a revised Customer Growth adjustment used in the calculation of normalized test period sales shown on Exhibit 2, Schedule 2, Exhibit 3 and Exhibit 4 and is described further below. The third update relates to an inadvertent scrivener's error when picking up the (over)/under balance for the residential class from the April 2018 Monthly Fuel Reports, shown in Exhibit 3, pages 1 and 2. The fourth 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, 2019. The fifth update

is to reflect the final total system peak kWs of 18,875,799 on Exhibit 4, Line 8. The sixth update is to include a revised December 2018 Schedule 3 – Purchased Power and Interchange System Report, page 3 of 4. A version that had been subsequently amended was inadvertently included in Exhibit 6 - December 2018 Monthly Fuel Reports.

Q. PLEASE EXPLAIN THE REASON FOR UPDATING THE WEATHER NORMALIZATION ADJUSTMENT.

A. During a subsequent review of the weather normalization calculation, an error was discovered in the model's calculation of the wholesale adjustment amount. This correction, as shown on Revised McGee Workpaper 12, resulted in a 129,467 MWh reduction in the wholesale adjustment, thus reducing the system adjustment as well. However, there is no impact to customer rates due to this update. System normalized sales are only used on Exhibit 2, Schedule 2, which are filed for information purposes only.

Q. PLEASE EXPLAIN THE REASON FOR UPDATING THE CUSTOMER GROWTH ADJUSTMENT.

A. Public Staff identified a number of recommended adjustments in the calculation of the customer growth that the Company agreed were necessary, resulting in a change of 87,739 in total NC retail MWhs. In addition, the SC residential regression model has been updated to use weather adjusted values for energy usage during the test period instead of billed values. The revised system MWh adjustment for customer growth is 419,697 MWhs, an increase of 110,554 MWhs.

Q. HOW DID THE FUEL AND FUEL-RELATED COST RECOVERY BALANCE CHANGE DUE TO THE CORRECTION OF THE SCRIVENER'S ERROR REFLECTED IN APRIL 2018 ON EXHIBIT 3?

A. The under-collection balance as 12/31/2018 increased by $26,999 due to the correction of the clerical error reflected in the residential class.

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

A. The Company experienced an under-collection of $29,483,760 during the months January through March 2019. As shown on Revised McGee Exhibit 3, the incorporation of the update test period under-collection balance resulted in an under-recovered balance at March 31, 2019 of $87,165,106.

Q. WHAT IS THE RATE IMPACT OF THESE UPDATES?

A. The NC Retail Total Fuel Costs were increased by $ 29,263,025 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 Revised 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	1.8575	1.9237	1.8760	1.8901
EMF Increment (Decrement)	0.1124	0.1396	0.2366	0.1501
Net Fuel and Fuel Related Costs Factors	1.9699	2.0633	2.1126	2.0402

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 1.68% increase on customers' bills, as compared to the previously filed increase of 1.05%.

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

A. Yes, it does.

(WHEREUPON, Revised Second Supplemental McGee Exhibit 1, Second Supplemental McGee Exhibit 2, Revised Second Supplemental McGee Exhibit 3, Second Supplemental McGee Exhibits 4 and 5, and Revised Second Supplemental McGee Exhibit 6 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled second supplemental testimony of KIMBERLY McGEE is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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	)))))	**SECOND SUPPLEMENTAL TESTIMONY OF KIMBERLY D. MCGEE FOR DUKE ENERGY CAROLINAS, LLC**

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 26, 2019, I caused to be pre-filed with the Commission my direct testimony and 6 exhibits and 14 supporting workpapers and on April 30, 2019, I caused to be pre-filed with the Commission my Supplemental testimony and 6 exhibits and 14 supporting workpapers.

Q. YOUR SECOND SUPPLEMENTAL TESTIMONY INCLUDES 5 REVISED EXHIBITS. WERE THESE REVISED 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 Exhibit 4: MWh Sales, Fuel Revenue, and Fuel and Fuel-Related Expense, as well as System Peak for the test period.

Revised McGee Exhibit 6 – December 2018 Monthly Fuel Reports.

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

A. The purpose of my testimony is to present revised rates reflecting the correction of the (Over)/Under-Collection balance for the months of September 2018 – December 2018. The monthly fuel filing Schedule 4 had incorrectly used the total fuel factor, including the EMF component related to prior periods, in its calculation of monthly fuel revenues collected for purposes of determining (over)/under recovery of monthly fuel costs. The revised calculations properly exclude the EMF amounts billed related to prior periods from the computation of current month amounts. In order to mitigate the increase in customers' rates, the Company has also elected to withdraw their prior request (made in the first supplemental filing) to include the update period of January 2019 – March 2019.

Q. HOW DID THE FUEL AND FUEL-RELATED COST RECOVERY BALANCE CHANGE DUE TO THE CORRECTION OF THE BILLING RATES FOR SEPTEMBER 2018 -DECEMBER 31, 2018 ON EXHIBIT 3?

A. The under-collection balance as 12/31/2018 increased by $20.5 million.

Q. WHAT IS THE RATE IMPACT OF THESE UPDATES?

A. As a result of the two proposed changes – (1) correcting the September 2018 – December 2018 under-collection balance and (2) withdrawing the request to include the under-collection balance for the update period January 2019 – March 2019 – the NC Retail Total Fuel Costs were decreased by $ 8,946,290 from the amounts filed on April 30, 2019 in my Revised Exhibit 2, Schedule 1, page 3. The

components of the proposed fuel and fuel-related cost factors by customer class, as shown on Revised 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	1.8126	1.9561	1.8934	1.8901
EMF Increment (Decrement)	0.1375	0.0927	0.2089	0.1346
Net Fuel and Fuel Related Costs Factors	1.9501	2.0488	2.1023	2.0247

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 1.49% increase on customers' bills, as compared to the previously filed increase of 1.68%.

Q. DOES THIS CONCLUDE YOUR PRE-FILED SECOND SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

CHAIR MITCHELL: Moving on to intervenors.

MS. THOMPSON: Yes, thank you, Madam Chair. As you had indicated earlier, Sierra Club has waived cross examination of all witnesses. Counsel for Duke Energy Carolinas has agreed not to object to the introduction of confidential response to Public Staff Data Request 11-2, both the narrative responses and Excel spreadsheets that were attached thereto, as an exhibit. I have that, I haven't premarked it because I wasn't sure how the Commission would prefer that I mark it. I think one option could just be Sierra Club Confidential Exhibit 1 --

CHAIR MITCHELL: Okay.

MS. THOMPSON: -- if that's acceptable with the Commission.

CHAIR MITCHELL: That is acceptable.

MS. THOMPSON: So I will move that Confidential Sierra Club Exhibit 1 be admitted into evidence under seal and made a part of the record in this proceeding. And I have the copies that I could pass out now or after the hearing recesses.

CHAIR MITCHELL: Let's hold it until after the hearing. And, without objection, that motion is allowed.

MS. THOMPSON: Thank you.

CHAIR MITCHELL: And please do ensure that it's marked as confidential.

MS. THOMPSON: Okay. Thank you. Yes, I will. Thank you, Madam Chairman.

(WHEREUPON, Confidential Sierra Club Exhibit 1 is received into evidence.)

CHAIR MITCHELL: Ms. Downey.

MS. DOWNEY: Good morning. Pursuant to North Carolina General Statute § 62-68 and the Commission's Order of June 7, 2019, the Public Staff moves that the Affidavits of Jay B. Lucas and Jenny Li be admitted into evidence.

CHAIR MITCHELL: Without objection, that motion is allowed.

(WHEREUPON, the prefiled affidavit and Appendix A of JAY B. LUCAS is copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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	))))	AFFIDAVIT OF JAY B. LUCAS

STATE OF NORTH CAROLINA

COUNTY OF WAKE

I, Jay B. Lucas, first being duly sworn, do depose and say:

I am an engineer with the Electric 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 this affidavit is to present the Public Staff's 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 26, 2019, application and testimony, April 30, 2019 supplemental testimony and revised exhibits, and May 15, 2019 supplemental testimony and revised exhibits. I have reviewed DEC's application, its prefiled testimony and exhibits, fuel-related costs, test period baseload power plant performance reports, the current coal, natural gas, nuclear fuel, and reagents markets, and various documents

related to test year power plant outages and purchased power costs. I have also reviewed the affidavit of Public Staff witness Jenny Li.

For this proceeding, the test period is January 1, 2018, through December 31, 2018, and the billing period is September 1, 2019, through August 31, 2020.

Of particular concern to the Public Staff in its investigation of the test year fuel costs was the significant under-recovery that took place due to the Company's greater than expected fuel costs in January 2018. After reviewing discovery and discussing the issue with DEC employees, the Public Staff is satisfied that the January 2018 fuel costs were reasonable and prudently incurred. However, DEC, like other utilities, has increased its reliance on natural gas to produce electricity and serve load.[1] As utilities have significantly increased their reliance on a fuel with greater price variances (compared to nuclear and coal) in order to more economically serve their customers, these same customers are exposed to greater risk of fuel cost under- and over-recoveries despite the overall decreasing cost of natural gas. Increased natural gas consumption, coupled with recent winter weather events of the last few years, have caused exposure to higher than anticipated short-term natural gas prices. Given the increased risk of under-recoveries if natural gas prices are not forecasted as accurately as possible, the Public Staff believes that the Company should evaluate historic price fluctuations and whether its current method of

[1] In 2017, the Company's natural gas burn was 80.8 MMBTU, while the current billing period is expected to result in consumption of 147.2 MMBTU. Dual Fuel Optionality conversion of some plants (Cliffside, Belews Creek, Marshall) to allow them to burn both coal and natural gas contributes to natural gas consumption projections.

forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs.

I believe the projected fuel and reagent prices set forth in the testimony of DEC witnesses McGee, Grant, and Houston were calculated appropriately for purposes of this proceeding. DEC's proposed fuel and fuel-related costs are based on a 92.95% system nuclear capacity factor.[2] Based on my investigation, I have determined that the projected fuel and fuel-related costs set forth in DEC's testimony, and the prospective components of the total fuel factor, have been calculated in accordance with the requirements of N.C. Gen. Stat. § 62-133.2.

Public Staff witness Li describes the Public Staff's review of the test period Experience Modification Factor in her affidavit, and I have incorporated her recommendations in Table 1 below.

The Public Staff recommends approval of the fuel components and total fuel factors (excluding the regulatory fee) shown in Table 1:

[2] The Company's actual system nuclear capacity factor for the test year was 95.29%. 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 90.21% during the test period.

TABLE 1 – Total Proposed Fuel and Fuel-Related Cost Factors (¢ per kWh)

Rate Class	Base & Prospective	EMF and EMF Interest	Total Fuel Factor
Residential	1.8126	0.1375	1.9501
General Service/Lighting	1.9561	0.0927	2.0488
Industrial	1.8934	0.2089	2.1023

For comparison, Table 2 below provides the existing fuel and fuel-related cost factors (excluding the regulatory fee) approved in Docket No. E-7, Sub 1163:

TABLE 2 – Total Existing Fuel and Fuel-Related Cost Factors (¢ per kWh)

Rate Class	Base & Prospective	EMF	Total Fuel Factor
Residential	1.7003	0.0980	1.7983
General Service/Lighting	1.8314	0.1068	1.9382
Industrial	1.8020	0.2213	2.0233

This completes my affidavit.

Jay B. Lucas

Sworn to and subscribed before me,

this the 20th day of May, 2019.

Notary Public

Joanne M. Berube
NOTARY PUBLIC
WAKE COUNTY, N.C.
My Commission Expires 12-17-2022.

JOANNE M. BERUBE
Printed Name

My Commission Expires: 12/17/2022

Appendix A

Jay B. Lucas

I graduated from the Virginia Military Institute in 1985, earning a Bachelor of Science Degree in Civil Engineering. Afterwards, I served for four years as an officer in the U. S. Air Force performing many civil and environmental engineering tasks. I left the Air Force in 1989 and attended the Virginia Polytechnic Institute and State University (Virginia Tech), earning a Master of Science degree in Environmental Engineering. After completing my graduate degree, I worked for an engineering consulting firm and worked for the North Carolina Department of Environmental Quality in its water quality programs. Since joining the Public Staff in January 2000, I have worked on utility cost recovery, renewable energy program management, customer complaints, and other aspects of utility regulation. I am a licensed Professional Engineer in North Carolina.

(WHEREUPON, the prefiled affidavit and Appendix A of JENNY X. LI is copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1190

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, 2018.

In its application, filed on February 26, 2019, 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	0.1108 cents per kWh
General Service/Lighting	0.0632 cents per kWh
Industrial	0.1476 cents per kWh

On April 30, 2019, 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 six updates to numbers presented in witness McGee's direct exhibits and workpapers. They are as follows:

(1) Update the wholesale weather normalization adjustment used in the calculation of normalized test period sales. The update to the weather normalization relates to an error in the model's calculation of wholesale coefficients and has no impact on customer rates in this case;

(2) Update the Customer Growth adjustment. This update results in a change of 87,739 in total N.C. retail MWh;

(3) Correct the under-collected balance for the residential class in the amount of $26,999, due to an inadvertent scrivener's error shown in Exhibit 3, Pages 1 and 2;

(4) Update the EMF increment to incorporate the fuel and fuel-related cost recovery balance for January through March 2019, pursuant to Commission Rule R8-55(d)(3). The reported over/under-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;

(5) Reflect the final total system peak kW of 18,875,799 set forth on Exhibit 4; and

(6) Include a revised December 2018 Schedule – 3 Purchased Power and Interchange System Report, page 3 of 4.

On May 15, 2019, DEC filed the Second Supplemental Testimony of Kimberly D. McGee with Revised McGee Exhibits and supporting workpapers. Witness McGee's second supplemental testimony and revised exhibits reflect a correction of the over/under-recovery balance for the months of September 2018 through December 2018. The Company's monthly fuel filing Schedule 4 had incorrectly used the total fuel factor in its calculation of monthly fuel revenues collected for purposes of determining over/under-recovery of monthly fuel costs, instead of the prospective, or forward-looking, fuel factor. The revised calculations have corrected the error. The Company has also elected to withdraw its prior request set forth in the first supplemental filing to include the update period of January 2019 through March 2019.

Revised McGee Exhibit 1 included in witness McGee's second 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	0.1375 cents per kWh
General Service/Lighting	0.0927 cents per kWh
Industrial	0.2089 cents per kWh

In computing these EMF riders, the Company excluded the over/under-recovery for the months of January 2018 through March 2018 (because it was included in last year's EMF calculation), and included the under-recovery related to the coal inventory rider established in Ordering Paragraph 27 of the Commission's June 22, 2018 *Order Accepting Stipulation, Deciding Contested Issue and Requiring Revenue Reduction* in Docket No. E-7, Sub 1146. The coal inventory rider was terminated effective for service on and after December 1, 2018.

In witness McGee's Revised Exhibits filed on May 15, 2019, DEC's proposed revised under-recovery of fuel for each of the North Carolina retail customer classes is as follows:

Residential	$30,299,742
General Service/Lighting	$21,853,594
Industrial	$26,041,062

The revised riders were calculated by dividing the fuel cost under-recoveries by DEC's normalized test year N.C. retail sales of 22,043,791 megawatt-hours (MWh) for the residential class, 23,564,462 MWh for the general service/lighting class, and 12,465,801 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, site visits to the Company's offices, 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 $30,299,742 for the residential class, $21,853,594 for the general service/lighting class, and $26,041,062 for the industrial class, and normalized North Carolina retail sales of 22,043,791 MWh for the residential class, 23,564,462 MWh for the general service/lighting class, and 12,465,801 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	0.1375 cents per kWh
General Service/Lighting	0.0927 cents per kWh
Industrial	0.2089 cents per kWh

I have provided these amounts to Public Staff witness Jay Lucas 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 20 day of May, 2019.

NEHA R PATEL
NOTARY
MY COMMISSION EXPIRES
3/18/2024
PUBLIC
WAKE COUNTY, NC

NRPatel

Notary Public

My Commission Expires: 3/18/2024

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 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 and fuel 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: And I believe that is all of the evidence in this proceeding. Before we adjourn let's discuss proposed orders. We typically accept them 30 days from the filing of the notice of transcript.

MR. JIRAK: Yes, we can do that.

MS. DOWNEY: Yes.

CHAIR MITCHELL: Thank you. Any other matters before we adjourn?

(No response)

CHAIR MITCHELL: Thank you, and we are adjourned.

(The hearing was adjourned at 9:39 a.m.)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell

Kim T. Mitchell
Court Reporter