Jack E. Jirak
Associate General Counsel

Mailing Address:
NCRH 20 / P.O. Box 1551
Raleigh, NC 27602

o: 919.546.3257
f: 919.546.2694

jack.jirak@duke-energy.com

July 29, 2019

VIA ELECTRONIC FILING

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

**RE: Joint Proposed Order of Duke Energy Carolinas, LLC and the Public Staff
Docket No. E-7, Sub 1190**

Dear Ms. Jarvis:

Enclosed for filing in the above-referenced docket please find the *Joint Proposed Order* of Duke Energy Carolinas, LLC ("DEC") and the Public Staff. An electronic copy is being emailed to briefs@ncuc.net.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,

Jack E. Jirak

Enclosure

cc: Parties of Record

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 Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	**JOINT PROPOSED ORDER OF DUKE ENERGY CAROLINAS, LLC AND THE PUBLIC STAFF**

HEARD: Tuesday, June 11, 2019, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

Jack Jirak
Associate General Counsel
Duke Energy Corporation
NCRH 20/P.O. Box 1551
Raleigh, North Carolina 27602-1551

Robert W. Kaylor
Law Office of Robert W. Kaylor, P.A.
353 Six Forks Road, Suite 260
Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc. (“CUCA”):

Robert F. Page
Crisp & Page, PLLC
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

For Sierra Club:

Gudrun Thompson
Senior Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association (“NCSEA”):

Benjamin Smith
Regulatory Counsel
4600 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

For Carolinas Industrial Group for Fair Utility Rates III (“CIGFUR”):

Warren K. Hicks.
Bailey & Dixon
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

For the Using and Consuming Public:

Dianna Downey
Staff Attorney
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On February 26, 2019, Duke Energy Carolinas, LLC (“Duke Energy Carolinas,” “DEC,” or the “Company”) filed an application pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kimberly D. McGee, Eric S. Grant, Regis Repko, Steven D. Capps, and Kevin Y. Houston.

Petitions to intervene were filed by CIGFUR on February 28, 2019; by CUCA on March 6, 2019; by NCSEA on March 19, 2019; and by the Sierra Club on May 20, 2019. The Commission granted CUCA's petition to intervene on March 7, 2019, CIGFUR's petition to intervene on March 8, 2019, NCSEA's petition to intervene on March 20, 2019, and the Sierra Club's petition on May 29, 2019.

On March 8, 2019, the Commission issued an *Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice*, in which the Commission set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DEC rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

On March 18, 2019, the Commission entered an *Order Rescheduling Hearing, Intervention and filing of Testimony dates, and Revising Public Notice.* That order provided that the direct testimony of the Public Staff and other intervenors should be filed on May 20, 2019, that rebuttal testimony should be filed on May 30, 2019, and that a hearing on this matter would be held on June 11, 2019.

The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On April 30, 2019, DEC filed the supplemental testimony, exhibits and work papers of Kimberly D. McGee, in which she presented revised rates reflecting the impacts related to six updates to numbers presented in her direct exhibits and workpapers, which resulted in an overall increase in the amount requested in the original application.

On May 2, 2019, the Commission issued an *Order Requiring Publication of Second Public Notice.*

On May 15, 2019, DEC filed the second supplemental testimony and exhibits of Kimberly D. McGee, presenting revised rates reflecting the correction of the (Over)/Under-Collection balance for the months of September 2018-December 2018, which resulted in an increase in the amount requested in the original application. In order to mitigate the increase in customers' rates, the Company elected to withdraw their prior request (made in witness McGee's first supplemental filing) to include the update period of January 2019-March 2019.

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

On June 3, 2019, DEC filed a motion to excuse all Company and Public Staff witnesses. On June 6, 2019, Sierra Club filed a response to DEC's motion, stating that Sierra Club did not object, given that DEC indicated that it would not object to certain responses to data requests being entered into evidence at the hearing. On June 7, the Commission granted the motion and excused all DEC and Public Staff witnesses from appearing at the evidentiary hearing.

On May 14, 2019, DEC filed affidavits of publication indicating that the initial public notice had been provided in accordance with the Commission's procedural order. On June 4, 2019, DEC filed affidavits of publication indicating that the second public notice had been provided in accordance with the Commission's May 2, 2019 order.

The case came on for hearing as scheduled on June 11, 2019. The prefiled direct and supplemental testimonies of DEC's witnesses, the prefiled affidavits of the Public

Staff's witnesses, and Confidential Sierra Club Exhibit 1 were received into evidence. No other party presented witnesses or exhibits, and no public witnesses appeared at the hearing.

Based upon the Company's verified application, the testimony, affidavits, and exhibits received into evidence at the hearing and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to N.C. Gen. Stat. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended December 31, 2018 ("test period").

3. In its application and direct, supplemental, and second supplemental testimony including exhibits in this proceeding, DEC requested a total increase of $68.6 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEC included Experience Modification Factor ("EMF") riders to take into account fuel and fuel-related cost under-recoveries and over-recoveries experienced during the test period, with an overall under-recovery of $78.2 million.

4. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

5. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent. However, given DEC's increased reliance on natural gas and the resulting increased risk of under-recoveries if natural gas prices are not forecasted as accurately as possible, the Company should evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs. The Company shall report the results of this evaluation in the next fuel proceeding.

6. The test period per book system sales are 90,487,628 megawatt-hours ("MWh"). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 97,045,431 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	22,653,740
Natural Gas, Oil and Biomass	16,236,067
Nuclear	44,770,657
Hydro – Conventional	2,877,050
Hydro Pumped Storage	(529,226)
Solar DG	130,018
Purchased Power – subject to economic dispatch or curtailment	8,564,915
Other Purchased Power	2,551,485
Interchange In/Out	(209,275)
Total Net Generation	**97,045,431**

7. The appropriate nuclear capacity factor for use in this proceeding is 92.95%.

8. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 58,074,054 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	22,043,791
General Service/Lighting	23,564,462
Industrial	12,465,801
Total	**58,074,054**

9. The projected billing period (September 2019-August 2020) sales for use in this proceeding are 87,243,844 MWh on a system basis and 57,717,997 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,397,068
General Service/Lighting	23,381,644
Industrial	12,939,285
Total	**57,717,997**

10. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 92,298,568 MWh and is categorized as follows:

Generation Type	MWh
Coal	18,355,203
Gas Combustion Turbine (CT) and Combined Cycle (CC)	19,943,217
Nuclear	43,570,151
Hydro	4,839,425
Net Pumped Storage Hydro	(3,874,211)
Solar Distributed Generation (DG)	184,444
Purchased Power	9,280,339
Total	**92,298,568**

11. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

a. The coal fuel price is $31.06/MWh.

b. The gas CT and CC fuel price is $24.17/MWh.

c. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, "Reagents") is $24,959,649.

d. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.12/MWh.

e. The total system purchased power cost (including the impact of Joint Dispatch Agreement ("JDA") Savings Shared) is $314,814,153.

f. System fuel expense recovered through intersystem sales is $16,986,301.

12. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,090,922,448.

13. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $78.2 million, consisting of an under-recovery for the residential, general service/lighting, and industrial classes of $30.3 million, $21.9 million and $26.0 million respectively.

14. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1163 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

15. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.8126 cents/kilowatt-hour ("kWh") for the Residential class; 1.9561 cents/kWh for the General Service/Lighting class; and 1.8934 cents/kWh for the Industrial class.

16. The appropriate EMF decrements established in this proceeding, excluding the regulatory fee, are as follows: 0.1375 cents/kWh for the Residential class; 0.0927 cents/kWh for the General Service/Lighting class; and 0.2089 cents/kWh for the Industrial class.

17. The total net fuel and fuel-related costs factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.9501 cents/kWh for the Residential class; 2.0488 cents/kWh for the General Service/Lighting class; and 2.1023 cents/kWh for the Industrial class.

18. The base fuel and fuel-related costs as approved in Docket No. E-7, Sub 1146 of 1.7828 cents/kWh, 1.9163 cents/kWh, and 2.0207 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively will be adjusted by amounts equal to 0.0298 cents/kWh, 0.0398 cents/kWh, and (0.1273) cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively. The resulting approved fuel and fuel-related costs will be further adjusted by EMF increments totaling 0.1375 cents/kWh, 0.0927 cents/kWh, and 0.2089 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively.

<u>EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1</u>

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

<u>EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2</u>

N.C. Gen. Stat. § 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-

55(b) prescribes the 12 months ending December 31 as the test period for DEC. The Company's filing in this proceeding was based on the 12 months ended December 31, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Application, the direct, supplemental, and second supplemental testimony of Company witness McGee, and the entire record in this proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the direct testimony of Company witnesses Capps and Repko.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation ("NERC") Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and unusual events. Company witness Capps testified that the Company's seven nuclear units operated at a system average capacity factor of 95.29% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 95.58%, exceeded the five-year industry weighted average capacity factor of 90.21% for the period 2013-2017 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Capps testified that for the 19th consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, which included five refueling outages. 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 nine 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 the entire year, recorded the third best annual generation performance.

Company witness Repko testified concerning the performance of DEC's fossil, hydro, and solar assets. He stated that the primary objective of the Company's fossil, hydro, and solar generation department is to provide safe, reliable and cost-effective electricity to DEC's customers. Witness Repko further stated that DEC complies with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers.

Company witness Repko testified that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate 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 hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and, (4) starting reliability ("SR"), which represents the percentage of successful starts.

Company witness Repko presented the following chart, which shows operation results, as well as results from the most recently published NERC Generating Availability Brochure for the period 2013 through 2017, and is categorized by generator type:

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

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Repko testified that in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. During the test period, most of these units had at least one small planned outage to inspect and maintain plant equipment.

Witness Repko testified that 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.

Based on a preponderance of the evidence in the record, the Commission concludes that the Company managed its baseload plants during the test period prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in December 2014, and were in effect throughout the 12 months ending December 31, 2018. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses McGee, Grant, Repko, and Houston and the affidavit of Public Staff witness Lucas.

Company witness McGee testified that key factors in DEC's ability to maintain lower fuel and fuel-related rates for the benefit of customers include its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of Duke Energy Progress, LLC's ("DEP") and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined companies; and the joint dispatch of DEP's and DEC's generation resources.

Company witness Grant described DEC's fossil fuel procurement practices, set forth in Grant Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, conducting short-term and spot purchases to supplement term natural gas supply, and obtaining natural gas transportation for the generation fleet through a mix of long term firm transportation agreements and shorter term pipeline capacity purchases.

According to witness Grant, 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%. Witness Grant further testified that 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%.

Witness Grant stated that 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 approximately 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 primarily 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.

Witness Grant stated that 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.

He also testified that 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. 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.

Witness Grant stated that 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.

Witness Grant testified that this cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal 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.

Witness Grant further testified that 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 and 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.

According to witness Grant, DEC continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company expects to address any spot and long-term coal requirements throughout this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels.

Witness Grant also testified that 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 that includes contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption.

According to Witness Grant, 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.

Public Staff witness Lucas testified that 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. He stated that 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. Witness Lucas explained that 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. Witness Lucas stated that 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 forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs.

N.C. Gen. Stat. § 62-133.2(a1)(3) permits DEC to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Repko testified that the Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for nitrogen oxide ("NO_x)" and sulphur oxide ("SO_X") emissions. The selective non-catalytic reduction technology ("SCR" or "SNCR") 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 which use crushed limestone for sulfur dioxide (SO_2) removal. Cliffside Unit 6 has a state-of-the-art SO_2 reduction system which 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 (19% solution of NH_3) is introduced for NO_x removal.

Company witness Repko further testified that overall, the type and quantity of chemicals used to reduce emissions at the Company's plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and the level of emissions reduction required. He stated that 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. He also stated that the goal is to effectively comply with emissions regulations and provide the most efficient total-cost solution for operation of the unit.

Company witness Houston testified as to DEC's nuclear fuel procurement practices, which include 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. Witness Houston explained that for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, 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 the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces the Company'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.

N.C. Gen. Stat. §§ 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities;

and the fuel costs of other power purchases. Company witness Grant testified that DEP and DEC consider the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at generating units, estimated forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

Based upon the fuel procurement practices report and the evidence in the record, the Commission concludes that the Company's fuel procurement and power purchasing practices were reasonable and prudent during the test period. However, the Commission agrees with the Public Staff that given the Company's increased reliance on natural gas to produce electricity and serve load, and the possible exposure of customers to greater risk of fuel cost under- and over-recoveries, the Company should evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs and report the results of that evaluation in the Company's next fuel proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee.

According to the exhibits sponsored by Company witness McGee, the test period per book system sales were 90,487,628 MWh, and test period per book system generation and purchased power amounted to 97,045,431 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Revised McGee Exhibit 6):

Net Generation Type	MWh
Coal	22,653,740
Natural Gas, Oil and Biomass	16,236,067
Nuclear	44,770,657
Hydro – Conventional	2,877,050
Hydro Pumped Storage	(529,226)
Solar DG	130,018
Purchased Power – subject to economic dispatch or curtailment	8,564,915
Other Purchased Power	2,551,485
Interchange In/Out	(209,275)
Total Net Generation	**97,045,431**

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness McGee's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 90,487,628 MWh and system generation and purchased power of 97,045,431 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the direct testimony and exhibits of Company witness Capps.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and unusual events. The Company proposed using a 92.95% capacity factor in this proceeding based on the operational history of the Company's nuclear units and the number of planned outage days scheduled during the billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 90.21% for the period 2013-2017 as reported in the NERC Brochure during the period of 2013 to 2017.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, and the fact that the Public Staff did not dispute the Company's proposed capacity factor, the Commission concludes that the 92.95% nuclear capacity factor, and its associated generation of 58,459,031 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

<u>EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 - 10</u>

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee.

On her Revised Exhibit 4, Company witness McGee set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 58,074,054 MWh, comprised of Residential class sales of 22,043,791 MWh, General Service/Lighting class sales of 23,564,462 MWh, and Industrial class sales of 12,465,801 MWh.

Witness McGee used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Revised McGee Exhibit 2, Schedule 1, is 87,243,844 MWh. The projected level of generation and purchased power used was 92,298,568 MWh (calculated using the 92.95% capacity factor found reasonable and appropriate above), and was broken down by witness McGee as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	18,355,203
Gas Combustion Turbine (CT) and Combined Cycle (CC)	19,943,217
Nuclear	43,570,151
Hydro	4,839,425
Net Pumped Storage Hydro	(3,874,211)
Solar Distributed Generation (DG)	184,444
Purchased Power	9,280,339
Total	**92,298,568**

As part of her Workpaper 7, Company witness McGee also presented an estimate of the projected billing period North Carolina retail Residential, General Service/Lighting, and Industrial MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,397,068
General Service/Lighting	23,381,644
Industrial	12,939,285
Total	**57,717,997**

These class totals were used in Revised McGee Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits (normalized for customer growth and weather), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses McGee and Grant and the affidavit of Public Staff witness Lucas.

Company witness McGee recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $31.06/MWh.

B. The gas CT and CC fuel price is $24.17/MWh.

C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, "Reagents") is $24,959,649.

D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.12/MWh.

E. The total system purchased power cost (including the impact of Joint Dispatch Agreement ("JDA") Savings Shared) is $314,814,153.

F. System fuel expense recovered through intersystem sales is $16,986,301.

These amounts are set forth on or derived from Revised McGee Exhibit 2, Schedule 1. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his affidavit, Public Staff witness Lucas stated that, based on upon his review, it appears that the projected fuel and reagent 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.

No other party presented evidence on the level of DEC's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness McGee and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee and the affidavit of Public Staff witness Lucas.

Consistent with N.C. Gen. Stat. § 62-133.2(a2), witness McGee testified that the annual increase in the aggregate amount of purchased power costs under the relevant sections of N.C. Gen. Stat. §62-133.2(a1) does not exceed 2.5% of DEC's total North Carolina jurisdictional gross revenues for 2018.

According to Revised McGee Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,090,922,448. Public Staff witness Lucas did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North

Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $1,090,922,448 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 13-17

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee and the affidavits of Public Staff witnesses Lucas and Li.

Company witness McGee presented DEC's original fuel and fuel-related expense under-collection and prospective fuel and fuel-related cost factors. Company witness McGee's supplemental testimony and revised exhibits set forth the projected fuel and fuel-related costs, the amount of over/(under) collection for purposes of the EMF, the method for allocating the increase in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with exhibits and workpapers reflecting the following adjustments: (1) correction to the Company's weather normalization adjustment, (2) correction of the Company's customer growth adjustment, (3) correction of an inadvertent scrivener's error in the company's over/under recovery exhibit, and (4) inclusion of the over/under collection balances for the update period January – March 2019 in the over/under calculation. Company witness McGee's second supplemental testimony and revised exhibits set forth the projected fuel and fuel-related costs, the amount of over/(under) collection for purposes of the EMF reflecting the following adjustments: (1) Correction of Exhibit 3 under/(over) recovery balances due to an error found in the Schedule 4 monthly fuel reports filed with the Commission and (2) the removal of the update period January – March 2019. Public Staff witness Lucas recommended the approval of the prospective and EMF components and total fuel factors (excluding regulatory fee) set forth in Company witness McGee's second supplemental testimony.

Public Staff witness Li testified that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost under-recoveries of $30,299,742, $21,853,594, and $26,041,062 for the Residential, General Service/Lighting, and Industrial classes, respectively. She recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost under-recovery amounts and on the Company's proposed 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. She stated that 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

Company witness McGee calculated the Company's proposed fuel and fuel-related cost factors for which there is no specific guidance in N.C. Gen. Stat. § 62-133.2(a2) using a uniform bill adjustment method. She stated that 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. No party opposed the use of this allocation method. Public Staff witness Lucas recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Company witness McGee's second supplemental testimony and revised exhibits.

Based upon the testimony and exhibits in the record, the Commission concludes that DEC's projected fuel and fuel-related cost of $1,090,922,448 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that (1) DEC's EMFs proposed in this proceeding, excluding the regulatory fee and (2) DEC's prospective fuel and fuel-related cost factors proposed in this proceeding for each of DEC's rate classes are appropriate. Additionally, the Commission concludes that DEC's increase in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1163, other than those costs allocated pursuant to N.C. Gen. Stat. § 62-133.2(a2), should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEC's past fuel cases.

The following tables summarize the impact of the rates approved in this case and the rates approved in Docket No. E-7, Sub 1163 (excluding regulatory fee).

E-7 Sub 1163			
Description	**Residential cents/kWh**	**General Service Lighting cents/kWh**	**Industrial cents/kWh**
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	(0.0825)	(0.0849)	(0.2187)
EMF Component	0.0980	0.1068	0.2213
Total Fuel Factor	1.7983	1.9382	2.0233

E-7 Sub 1190			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	0.0298	0.0398	(0.1273)
EMF Component	0.1375	0.0927	0.2089
Total Fuel Factor	1.9501	2.0488	2.1023

Summary of Differences Sub 1190 — 1163 (excluding regulatory fee):

Change in Fuel Rates			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	-	-	-
Prospective Component	0.1123	0.1247	0.0914
EMF Component	0.0395	(0.0141)	(0.0124)
Total Fuel Factor	0.1518	0.1106	0.0790

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding of fact is contained in the testimony of Company witness McGee and in the affidavits of Public Staff witnesses Li and Lucas and is discussed in more detail in Evidence and Conclusions for Finding of Fact No. 5.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculations, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 1.9501 cents/kWh for the Residential class, 2.0488 cents/kWh for the General Service/Lighting class, and 2.1023 cents/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.8126 cents/kWh, 1.9561 cents/kWh, and 1.8934 cents/kWh, EMF increments of 0.1375 cents/kWh, 0.0927 cents/kWh, and 0.2089 cents/kWh, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after September 1, 2019, DEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 1.7828 cents/kWh, 1.9163 cents/kWh, and 2.0207 cents/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively as approved in Docket No. E-7, Sub 1163, by amounts equal to 0.0298 cents/kWh, 0.0398 cents/kWh, and (0.1273) cents/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively, and further, that DEC shall adjust the resulting approved fuel and fuel-related costs by EMF increments of 0.1375 cents/kWh for the Residential class, 0.0927 cents/kWh for the General Service/Lighting class, and 0.2089 cents/kWh for the Industrial class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through August 31, 2020.

2. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments as soon as practicable.

3. That DEC shall work with the Public Staff to prepare a notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub ____, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in both dockets.

4. That the Company shall evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs and report the results of that evaluation in the Company's next fuel proceeding

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of _______, 2019.

NORTH CAROLINA UTILITIES COMMISSION

M. Lynn Jarvis, Chief Clerk

CERTIFICATE OF SERVICE

I certify that a copy of the Joint Proposed Order of Duke Energy Carolinas, LLC and the Public Staff, in Docket No. E-7, Sub 1190, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 29th day of July, 2019.

Jack E. Jirak
Associate General Counsel
Duke Energy Corporation
P.O. Box 1551/NCRH 20
Raleigh, North Carolina 27602
(919) 546-3257
Jack.jirak@duke-energy.com