PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, June 7, 2022

TIME: 10:50 a.m. - 11:59 a.m.

DOCKET NO: E-7, Sub 1263

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

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.

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC:
Ladawn Toon, Esq.
Associate General Counsel
411 Fayetteville Street
Raleigh, North Carolina 27601

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

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:
Craig Schauer, Esq.
Brooks Pierce
150 Fayetteville Street, Suite 1700
Raleigh, North Carolina 27601

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES, III:
Christina Cress, Esq.
Bailey & Dixon, L.L.P.
Post Office Box 1351
Raleigh, North Carolina 27602-1351

A P P E A R A N C E S Cont'd.:

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Peter H. Ledford, Esq.
Taylor Jones, Esq.
4600 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SIERRA CLUB:
Gudrun Thompson, Esq.
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR THE USING AND CONSUMING PUBLIC:
William E.H. Creech, Esq.
North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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

E X A M I N A T I O N S

E X A M I N A T I O N S Cont'd.:

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 and go on the record, please. I'm Charlotte Mitchell, Chair of the Utilities Commission. With me are Commissioners Brown-Bland, Clodfelter, Duffley, McKissick, Hughes, and Kemerait.

I now call for hearing Docket E-7, Sub 1263, In the Matter of Application of Duke Energy Carolinas, LLC, Pursuant to North Carolina General Statute § 62-133.2 and Commission Rule R8-55 relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. Section 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 will be held the first Tuesday of June of each year and that DEC shall file its Application, direct testimony and exhibits, and shall publish notice prior to the hearing.

On March 1st, 2022, DEC filed its Application to adjust the fuel and fuel-related cost component of its electric rates, along with the direct testimony of Witnesses Sykes, Houston, Verderame, Walsh and Capps.

The following parties have petitioned to and been allowed to intervene in this proceeding, including Carolina Water Utility Customers Association, Inc., or CUCA; the North Carolina Sustainable Energy Association, NCSEA; the Carolina Industrial Group for Fair Utility Rates III, CIGFUR III; and the Sierra Club. Public Staff's participation in the proceeding is recognized pursuant to Statute and Rule.

On March 14th, 2022, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. The Order scheduled DEC's fuel hearing for today, Tuesday, June 7th, 2022, immediately following the hearing in Docket Number E-7, Sub 1262, which began at ten o'clock this morning.

On May 9th, DEC filed the supplemental testimony and exhibits of Witness Sykes and the direct testimony of Witness Johnson.

On May 17th, 2022, the Public Staff filed the Affidavit of Chiu and the joint testimony of Witnesses Lawrence and Metz.

Also on May 17th, the Sierra Club filed the direct testimony and exhibits of Witness Lander.

On May 26th, DEC filed the rebuttal testimony of Witness Verderame.

On June 3rd, DEC and the Public Staff filed a joint motion for witnesses to be excused from this hearing.

And then by Order issued on June 6th, DEC Witnesses Houston, Walsh, Capps and Johnson, and Public Staff Witness Chiu, and Sierra Club Witness Lander were excused from attending the expert witness hearing, but DEC Witnesses Sykes and Verderame and Public Staff Witnesses Lawrence and Metz were not excused.

On June 3rd and on June 6th, DEC filed the required Affidavits of Publication in this docket.

That brings us to this morning.

Pursuant to the State Government Ethics Act, I remind members of the Commission of our duty to avoid conflicts of interest, and inquire at this time if any member of the Commission has a known conflict of interest with respect to the matters coming before us?

(No response)

The record will reflect that no conflicts have been identified, so we'll go ahead.

I now call for appearances of counsel, beginning with the Applicant.

MR. KAYLOR: Madam Chair, Members of the Commission, Robert Kaylor appearing on behalf of Duke Energy Carolinas.

CHAIR MITCHELL: Good morning, Mr. Kaylor.

MS. TOON: Good morning, Chair Mitchell. Again, Ladawn Toon on behalf of Duke Energy Carolinas.

CHAIR MITCHELL: Good morning, Ms. Toon.

MR. CREECH: Good morning, Chair Mitchell and Commissioners. William Creech on behalf of the Public Staff and the Using and Consuming Public. Thank you.

CHAIR MITCHELL: Good morning, Mr. Creech.

MS. CRESS: Good morning, Chair Mitchell and Members of the Commission. Christina Cress with the Law Firm of Bailey & Dixon appearing on behalf of CIGFUR III.

CHAIR MITCHELL: Good morning, Ms. Cress.

MR. SCHAUER: Good morning. Craig Schauer from the Law Firm of Brooks Pierce here on behalf of Carolina Utility Customers Association.

CHAIR MITCHELL: Good morning, Mr. Schauer.

MS. JONES: Good morning, Chair Mitchell, Commissioners. Taylor Jones on behalf of the North Carolina Sustainable Energy Association.

CHAIR MITCHELL: Good morning, Ms. Jones.

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

CHAIR MITCHELL: Good morning, Ms. Thompson. And Mr. Ledford, I see you back there. Are you making an appearance or are you letting your --

MR. LEDFORD: Yes, I'm making an appearance.

CHAIR MITCHELL: Okay. Mr. Ledford is in.

Before we move to the expert witness hearing, I will check in with the Public Staff to see if the Public Staff has identified any public witnesses who wish to be heard today.

MR. CREECH: We have not.

CHAIR MITCHELL: Okay. Looking out into the room, if there is a public witness that wishes to be heard today, please identify yourself.

(No response)

I am seeing no such public witnesses identify themselves. So we will now move into the expert witness hearing.

Before we begin, any preliminary matters?

MR. KAYLOR: Nothing other than I guess it might be appropriate for me to go ahead and introduce into the record the testimony of our Witnesses Steven Capps, Bryan Walsh, Kevin Houston and David Johnson since no parties had any cross of those witnesses.

CHAIR MITCHELL: All right. Mr. -- let's start with the Application first --

MR. KAYLOR: Yes, and the Application.

CHAIR MITCHELL: -- and then we will go from there.

MR. KAYLOR: The Application; and then for Capps, his direct testimony consisting of 14 pages and one exhibit; for Walsh, direct testimony of 11 pages; for Houston, nine pages of direct testimony and two exhibits; and for Witness Johnson, I think it was just a couple of pages from Witness Johnson, also.

CHAIR MITCHELL: All right. Let me check in to see if there are any objections to DEC's motion.

MR. CREECH: No objection.

CHAIR MITCHELL: Hearing no objection, your motion is allowed.

MR. KAYLOR: Thank you.

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

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

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

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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 13225 Hagers Ferry Road, Huntersville, 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 over 34 years of experience in the nuclear field in various roles with increasing responsibilities. I joined Duke Energy in 1987 as a field engineer at Oconee. During my time at Oconee, I served in a variety of leadership positions at the station, including Senior Reactor Operator, Shift Technical Advisor, and Mechanical and Civil Engineering Manager. In 2008, I transitioned to McGuire as the Engineering Manager. I later became plant manager and was named Vice President of McGuire in 2012. In December 2017, I was named Senior Vice President of Nuclear Corporate for Duke with direct executive accountability for Duke Energy's nuclear corporate functions, including nuclear corporate engineering, nuclear major projects, corporate governance and operation support and organizational effectiveness. I assumed my current role in October 2018.

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

A. Yes. I provided testimony and appeared before the Commission in DEC's fuel and fuel related cost recovery proceeding in Docket No. E-7, Sub 1163 and provided testimony in DEC's fuel and fuel related cost recovery proceedings in Docket No. E-7, Sub 1190, Docket No. E-7, Sub 1228, and Docket No. E-7, Sub 1250.

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, 2021 through December 31, 2021 ("test period"). I provide information about refueling outages completed during the period and also discuss the nuclear capacity factor being proposed by DEC for use in this proceeding in determining the fuel factor to be reflected in rates during the billing period of September 1, 2022 through August 31, 2023 ("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

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. The Company submitted a subsequent license renewal (SLR) application for the Oconee units in June 2021, and the application is currently under review by the Nuclear Regulatory Commission. If approved, the Oconee units would be licensed to operate for an additional 20 years. In 2019, the Company publicly announced intention to seek SLR for all 11 units operated by Duke Energy.

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.

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

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

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

A. The Company operated its nuclear stations in a reasonable and prudent manner during the test period, providing approximately 61% of the total power generated by DEC. During 2021, DEC's seven nuclear units collectively achieved a fleet capacity factor of 96.12%, marking the 22nd consecutive year in which DEC's nuclear fleet exceeded a system capacity factor of 90%. During the test period, McGuire Unit 1, Oconee Unit 1, and the Oconee station established new annual net generation records. The Company continued successful Covid-19 mitigation protocols and executed four refueling outages and achieved strong operational performance during the year. Catawba Unit 2 and Oconee Unit 2 entered their 2021 refueling outages after completing breaker-to-breaker continuous cycle runs. Catawba Unit 1 established a new Duke Energy refueling outage duration record. The 18.8-day refueling outage also established a new U.S. duration record for ice condenser pressurized water reactors.

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 92.07% for the period 2016 through 2020 for comparable units. The Company's 2021 capacity factor of

96.12% and 2-year average[1] of 95.58% both exceed the NERC average of 92.07%.

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, capacity factor, forced loss rate, industry performance index, and total operating cost. On a larger industry basis using early release data for 2021 from the Electric Utility Cost Group, all three of DEC's nuclear plants rank in the top quartile in total operating cost among the 55 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 50.9 million MWhs of additional, emissions-free generation over the past 22 years (as compared with production at a capacity factor of 90%), which is equivalent to an additional 10.5 months of output from DEC's nuclear fleet (based on DEC's average annual generation for the same 22-year period). These performance results demonstrate DEC's continuing success in achieving high performance without compromising safety and reliability.

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

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

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

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

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

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

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

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

A. Yes. DEC applies self-critical analysis to each outage and, using the benefit of hindsight, identifies every potential cause of an outage delay or event resulting in a forced or extended outage, and applies lessons learned to drive continuous improvement. The Company also evaluates the performance of each function and discipline involved in outage planning and execution to identify areas in which it can utilize self-critical observation for improvement efforts.

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

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

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

A. There were four refueling outages completed during the test period: Catawba Unit 2 in the spring of 2021, followed by McGuire Unit 2, Catawba Unit 1, and Oconee Unit 2 in the fall. Total days offline for refueling during the test period totaled 111.1 days compared to a total scheduled allocation of 114 days. Three of the four refueling outages were completed under allocation. The Catawba Unit 2 refueling outage extended 5.3 days beyond allocation due to an emergent weld overlay repair required on a reactor head penetration nozzle.

After completing a unit record 535-day continuous cycle run, Catawba Unit 2 was removed from service on March 27, 2021, for refueling. In addition to refueling, safety and reliability enhancing maintenance, inspections and testing were completed. The unit's three low-pressure turbines were replaced during the outage. The new turbines improve reliability and reduce required inspections and maintenance requirements. Other reliability enhancements included the replacement of the 2C reactor coolant pump seal, refurbishment of the 2A chemical injection pump seals, gear drive and motor, and refurbishment of the 2A2 component cooling water pump and motor. Other maintenance activities included tube replacements in the 2A component cooling water heat exchanger and corrective maintenance on the 2A moisture separator reheater tubes. The Unit 2 core exit thermocouple replacement project was completed. Steam generator activities included secondary side cleaning and primary side Eddy Current testing. Other testing and inspections completed during the outage included containment integrated leak rate testing and a volumetric reactor head inspection. The reactor head inspections identified a defect in one nozzle penetration necessitating a weld overlay repair. This emergent repair extended the outage by 5.3 days beyond the scheduled allocation. After refueling, maintenance, and inspections and testing were completed, the unit returned to service on May 3, 2021, for a total outage duration of 37.3 days.

McGuire Unit 2 was removed from the grid on September 11, 2021, for refueling. Large pump and motor reliability enhancements completed during the refueling outage included the 2A and 2C reactor coolant pump seals, the 2B2 component cooling pump motor, and the 2B nuclear service water motor replacements. Valve and actuator maintenance and replacements were completed on components of the safety injection, chemical volume control, instrument air, residual heat removal, and reactor coolant systems. The aging condenser cleaning system was also upgraded. Inspections completed included the reactor vessel 10-year in-service and material reliability program upper and lower internals inspections, and disassembly and inspection of the 2C low pressure turbine. Steam generator Eddy Current and 2B engineered safety features testing was completed. Once work activities, testing and inspections were completed, the unit returned to service on October 11, 2021. The total outage duration was 30.26 days compared to a 32-day scheduled allocation.

Catawba Unit 1 shut down for refueling on October 16, 2021. Along with routine refueling activities, safety and reliability enhancements and inspections were completed. Reliability enhancements completed during the outage included refurbishment of the 1A1 component cooling water pump and rewinding of the 1B hotwell pump motor. A modification on the Unit 1 main generator flexible links improved fit-up, current capacity, and cooling flow, permanently addressing a reliability challenge experienced earlier in the year. The Unit 1 digital fault recorder was replaced, and full functionality of the Unit 1 core exit thermocouples was restored with the replacement of 3 connectors. Inspections were completed on the number 2 main turbine control and number 1 combined intercept valves. After refueling, maintenance activities and inspections were completed, the unit returned to service on November 3, 2021. The 18.8-day refueling outage established a new refueling outage record for the Duke Energy fleet, low dose record for a Catawba refueling outage, and also established a U.S. industry record for refueling duration for ice condenser pressurized water reactors. The scheduled outage duration allocation was 25 days.

After completing a continuous cycle run of 701 days, Oconee Unit 2 shut down for refueling on November 12, 2021. Along with routine refueling activities, safety and reliability enhancements and inspections were completed. Large pump and motor reliability enhancing maintenance included the replacements of the 2A1 reactor coolant pump seals, 2A high pressure injection pump motor, 2B condensate booster pump motor, and 2B turbine electrohydraulic controls (EHC) pump. Other mechanical maintenance included the replacement of multiple feedwater system relief valves. Electrical work included bushing replacements on the CT-2 start-up transformer, and preventive maintenance on the Unit 2 main transformer, main feeder bus number 1, and multiple motor control centers. Upper core barrel bolt, CT2 4160-volt bus, 2TD 4160-volt switchgear, and condenser circulating water waterbox and inlet piping were among inspections completed during the outage. Testing activities included steam generator Eddy Current testing. After refueling, maintenance, inspections and testing completed, the unit returned to service on December 7, 2021, for a total duration of 24.75 days compared to a 25-day schedule allocation.

Q. WHAT OTHER OUTAGES OCCURRED DURING THE TEST PERIOD?

A. The fleet experienced 8.3 days of forced outages during the test period. McGuire Unit 2 was forced offline for just under 3 days due to oil contamination in the turbine lube oil, Catawba Unit 1 was forced offline for 2.8 days related to the main generator isolated bus phase flexible links, and Oconee Unit 2 experienced a 2.5-day forced outage after a reactor protection system actuation due to a signal spike.

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 93.94% 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 Sykes and exceeds the five-year industry weighted average capacity factor of 92.07% for comparable units as reported in the NERC Brochure during the period of 2016 to 2020.

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

A. Yes, it does.

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

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**BRYAN WALSH 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 Bryan Walsh 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 employed by Duke Energy and am the Vice President ("VP") of Central Operational Services and Oversight.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from The Catholic University of America with a Bachelor of Mechanical Engineering degree. I also graduated from the Georgia Institute of Technology with a Master of Science in Mechanical Engineering. I am a registered Professional Engineer in the State of North Carolina. My career began with Duke Energy as part of Duke / Fluor Daniel in 1999 as an associate engineer assisting in the design and commissioning of new combined-cycle power plants. I transferred to Duke Power in 2003 and worked in the Technical Services group for Fossil-Hydro. Since that time, I have held various roles of increasing responsibility in the generation engineering, operations areas, and project management, including the role of technical manager at DEC's Marshall Steam Station, and also station manager at Duke Energy Indiana's Gallagher Station & Markland Hydro Station. I was also the Midwest Regional Manager from 2012 to 2015, with overall responsibility for the Midwest Gas Turbine Fleet and various coal-fired facilities in Indiana and Kentucky. I was named General Manager for Outages & Projects in the Carolinas in 2015. Next, I became the General Manager of Fossil-Hydro Organizational Effectiveness in 2017. I assumed my current role in 2019.

Q. WHAT ARE YOUR CURRENT DUTIES AS VP OF CENTRAL OPERATIONAL SERVICES AND OVERSIGHT?

A. In this role, I am responsible for providing engineering, environmental compliance planning, technical services, and maintenance services, for Duke Energy's fleet of fossil, hydroelectric, and solar (collectively, "Fossil/Hydro/Solar") facilities.

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

A. Yes. I testified before the North Carolina Utilities Commission on behalf of the Company in its Duke Energy Progress fuel case in Docket No E-2, Sub 1250.

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 2021 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, 2021 through December 31, 2021 (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 14,274 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	6,087 MWs
Hydro -	3,354 MWs
Combustion Turbines ("CT") -	2,633 MWs
Combined Cycle Turbines ("CC")-	2,116 MWs
Solar -	71 MWs
Combined Heat and Power ("CHP") -	13 MWs

The coal-fired assets consist of four generating stations with a total of 10 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 10 coal-fired units are equipped with low NO_x burners.

The Company has a total of 31 simple cycle CT units, of which 29 are considered the larger group providing approximately 2,549 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 CC turbines, comprised of the Buck CC, Dan River CC and W.S. Lee CC facilities. These facilities are equipped with technology for emissions control, including SCRs, low NO_x burners, and carbon monoxide/volatile organic compounds catalysts. The Company's hydro fleet includes two pumped storage facilities with four units each that provide a total capacity of 2,300 MWs, along with conventional hydro assets consisting of 59 units providing approximately 1,054 MWs of capacity. The 71 MWs of solar capacity are made up of 17 rooftop solar sites providing 3 MWs of relative summer dependable capacity, the Mocksville solar facility providing 6 MWs of relative summer dependable capacity, the Monroe solar facility providing 22 MWs of relative summer dependable capacity, Woodleaf solar facility providing 2 MWs of relative summer dependable capacity, Gaston solar facility providing 10 MW of relative summer dependable capacity and Maiden Creek solar facility providing 28 MW of relative summer dependable capacity. Finally, the Company has the Clemson CHP that provides 13 MW of capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEC'S 2021 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. Allen Unit 3 was retired on 3/31/2021, and Allen Units 2 and 4 were retired on 12/31/2021. Bad Creek Unit 1 was uprated to bring an additional 80MW to the grid. W.S. Lee Unit 3 was placed in inactive reserve and will be retired 3/31/2022.

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, AND WHAT WAS THE HEAT RATE FOR DEC'S COAL-FIRED AND COMBINED CYCLE UNITS DURING THE REVIEW PERIOD?

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the review period, the Company's ten coal units produced 55% of the Fossil/Hydro/Solar generation, with the average heat rate for the coal-fired units being 9,736 Btu/kWh. The most active station during this period was Belews Creek, providing 43% of the coal generation for the DEC fleet with a heat rate of 9,685 Btu/kWh. During the review period, the Company's three combined cycle power blocks produced 38% of the Fossil/Hydro/Solar generation, with an average heat rate of 7,099 Btu/kWh.

Q. HOW MUCH GENERATION DID EACH TYPE OF FOSSIL/HYDRO/SOLAR GENERATING FACILITY PROVIDE FOR THE TEST PERIOD?

A. The Company's system generation was approximately 99 million MW hours ("MWhs") for the test period. The Fossil/Hydro/Solar fleet provided 38 million MWhs, or approximately 39% of the total generation. As a percentage of the total system generation, 21% was produced from coal-fired stations and approximately 15% from CC operations, 1% from CTs, 1% from hydro facilities, and 0.3% from solar.

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

A. 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.

At Belews Creek, Cliffside, and Marshall, dual fuel capabilities also promote efficiency, fuel flexibility and reduced cost. The units equipped with dual fuel capability can be economically dispatched based on need and cost, and the ability to switch fuels can allow the units to avoid forced outages if there is an issue with a fuel system or supply.

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; (4) starting reliability ("SR"), which represents the percentage of successful starts; and (5) equivalent forced outage factor ("EFOF")—which quantifies the number of period hours in

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

a year during which the unit is unavailable because of forced outages and forced deratings.

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 2016 through 2020 and is categorized by generator type. The NERC data reported represents an average of comparable units based on capacity rating. The data in the chart reflects DEC results compared to the NERC five-year averages.

Generator Type	Measure	Review Period	2016-2020	Number of Units
		DEC Operational Results	NERC Average	
Coal Fired Test Period	EAF	71.7%	76.1%	626
	EFOR	11.4%	10.2%	
	EFOF	6.9%	n/a	
Coal Fired Summer Peak	EAF	79.8%	n/a	n/a
Total CC Average	EAF	87.4%	84.9%	345
	NCF	74.0%	54.3%	
	EFOR	0.3%	5.0%	
	EFOF	0.3%	n/a	
Total CT Average	EAF	83.0%	86.6%	709
	SR	99.8%	98.5%	
Hydro	EAF	74.9%	79.4%	1059

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.

In the first half of 2021, Cliffside Unit 6 completed an outage to perform a boiler inspection, make repairs to the submerged flight conveyor, and perform maintenance on the baghouse. Marshall Unit 3 performed an outage to perform turbine and generator rotor inspections. Marshall Unit 4 completed an outage to perform a Mercury and Air Toxic Standards (MATS) inspection. Dan River CC completed an outage to perform a borescope inspection.

In the second half of 2021, Cliffside Unit 5 completed an outage to complete precipitator inspection/repairs, wash pre-heaters, repair cooling tower fans and replace the steam seal header relief valve. Belews Creek Unit 1 completed an outage to inspect/repair/replace portions of the turbine, perform repairs on the FGD overflow tank, and replace the rappers on the fly ash precipitator. Cliffside Unit 6 performed an outage to replace the SCR catalyst, install new pin mixers on the ash silo, and perform Balance of Plant maintenance. Marshall Unit 1 and Unit 2 completed outages for dual fuel gas installation and tie in. Lincoln CT Units 15 and Unit 16 both completed outages to upgrade protective relays for generators and transformers. Rockingham CT Unit 2 performed a hot gas path inspection.

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 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 Sykes 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, Houston Exhibits 1 and 2 are marked for identification as prefiled and received into evidence.)

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

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin Y. Houston and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am the Manager of Nuclear Fuel Supply for Duke Energy Carolinas, LLC ("DEC" or the "Company") and Duke Energy Progress, LLC ("DEP").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEC?

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

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

I have served as Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use. I became a registered professional engineer in the state of North Carolina in 2003.

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

A. Yes. I filed testimony in the DEC fuel and fuel-related cost recovery proceedings in Docket E-7, Sub 1250.

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, 2021 through December 31, 2021 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2022 through August 31, 2023 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 $39.49 per pound for uranium concentrates during the test period, representing a 16% decrease 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 increased 12% to $116.60 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 5%, 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 35%, respectively.

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

A. Prices in the uranium concentrate markets have increased due to production cutbacks and activity from financial investors. Industry consultants believe that recent production cutbacks have been warranted due to the previously existing oversupply conditions and that market prices need to further increase in the longer term to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements.

Market prices for conversion services have recently been stable primarily due to an increase in new production.

Market prices for enrichment services have recently increased primarily due to a reduction in available inventory supplies.

Fabrication is not a service for which prices are published; however, industry consultants expect fabrication prices will continue to generally trend upward.

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

A. 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 remain relatively flat, from 0.5726 cents per kWh incurred in the test period, to approximately 0.5773 cents per kWh in the billing period.

Q. WHAT STEPS IS DEC TAKING TO PROVIDE STABILITY IN ITS NUCLEAR FUEL COSTS AND TO MITIGATE PRICE INCREASES IN THE VARIOUS COMPONENTS OF NUCLEAR FUEL?

A. As I discussed earlier and as described in Houston Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEC relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating a range of pricing mechanisms, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEC's exposure to price volatility.

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

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

A. Yes, it does.

(WHEREUPON, the prefiled direct testimony of DAVID B. JOHNSON is copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF DAVID B. JOHNSON 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 David B. Johnson. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Corporation ("Duke Energy") as Director of Business Development and Compliance.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. My educational background includes a Bachelor of Science in Civil Engineering from the University of Tennessee. With respect to professional experience, I have been in the utility industry for over 38 years. I started as an associate Design Engineer in the Design Engineering Department at Duke Power in 1980. From 1991-1995, I worked for Duke Energy's affiliate companies Duke/Fluor Daniel and Duke Engineering & Services, Inc. In 1996, I worked in the initial Duke Power Trading Group in Charlotte, North Carolina, where I focused on marketing and business development and management until 2006. From 2006 to 2017, I worked as a Business Development Manager and Director in the Duke Energy wholesale and renewable energy areas. I began my current role in late 2017.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY

A. I am responsible for wholesale Power Purchase Agreements ("PPA") that Duke Energy enters into with third party suppliers. These include PPAs that Duke

Energy Carolinas, LLC ("DEC") and Duke Energy Progress ("DEP") enter into with Qualifying Facilities ("QFs"), renewable PPAs to comply with North Carolina's Renewable Energy Efficiency Portfolio ("REPS") standard, Competitive Procurement of Renewable Energy ("CPRE") PPAs, and conventional (non-renewable) PPAs. I have responsibility for the negotiation and execution of these PPAs, as well as the on-going management of all executed PPAs. In addition, I am responsible for Duke Energy's compliance with the REPS and the CPRE Program.

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

A. Yes. I most recently provided testimony in the 2018 Avoided Cost proceeding (NCUC Docket No. E-100, Sub 158) for DEC and DEP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present information and data required by the NCUC in accordance with the "Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations (Docket No. E-100, Sub 101 and E-100, Sub 158 – dated August 17, 2021). In this Order, the Commission directed DEC and DEP, in future fuel and fuel-related charge adjustment proceedings conducted pursuant to N.C. Gen. Stat. 62-133.2, to address the SISC avoidance process in their prefiled direct testimony, identify the specific facility(ies) and amount of SISC avoided in supporting exhibits and work papers, and the results of any audits performed on QFs seeking to avoid the SISC.

Q. DO YOU HAVE ANY INFORMATION TO REPORT AT THIS TIME?

A. No. There are currently no operating solar QF facilities at this time that contain energy storage systems. There are also currently no executed PPAs that contain SISC (sub 158 and later) that also include an energy storage system.

Duke will continue to monitor future solar QF PPAs with SISC and energy storage that provide notice to Duke that they intend to avoid some or all of the SISC. Duke will provide any data on the ability of these future QF facilities to avoid the SISC in future fuel proceedings for DEC and DEP.

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

A. Yes, it does.

MR. KAYLOR: We will proceed with the panel.

Mr. Verderame, would you state your name and business address for the record?

CHAIR MITCHELL: Let me get them sworn in first.

MR. KAYLOR: Oh, I'm sorry.

As a panel,

JOHN A. VERDERAME and BRYAN L. SYKES;

having been duly sworn,

testified as follows:

DIRECT EXAMINATION BY MR. KAYLOR:

Q State your name and business address for the record, please.

A (Mr. Verderame) Excuse me. John Verderame, 526 South Church Street, Charlotte, North Carolina.

Q And by whom are you employed and in what capacity?

A Duke Energy Progress. I am the Vice President of the Fuels and Systems Optimization Group.

Q And did you cause to be prefiled direct testimony consisting of 11 pages and 3 exhibits?

A I did.

Q And rebuttal testimony consisting of 11 pages?
A I did.
Q And if I ask you the questions today, would the answers be the same?
A They would.
Q Do you have any additions or corrections to that testimony?
A I do not.

MR. KAYLOR: At this time, I would ask that the direct testimony and exhibits -- direct testimony and rebuttal testimony be admitted into the record and the exhibits identified for the record, please?

CHAIR MITCHELL: Hearing no objection to the motion, the testimony will be copied into the record as if delivered orally from the stand. The exhibits will be marked for identification purposes as they were when prefiled.

(WHEREUPON, Verderame Exhibits 1 and 2, and Confidential Exhibit 3 are marked for identification.)

(WHEREUPON, the prefiled direct and rebuttal testimony of JOHN A. VERDERAME is copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**JOHN A. VERDERAME 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 John A. Verderame. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed as 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 received a Bachelor of Arts degree in Economics from the University of Rochester in 1983, and a Master's in Business Administration in Finance from Rutgers University in 1985. I have worked in the energy industry for 20 years. Prior to that, from 1986 to 2001, I was a Vice President in the United States (US) Government Bond Trading Groups at the Chase Manhattan Bank and Cantor Fitzgerald. My responsibilities as a US Government Securities Trader included acting as the Firm's market maker in US Government Treasury securities. I joined Progress Energy, in 2001, as a Real-Time Energy Trader. My responsibilities as a Real-Time Energy Trader included managing the real-time energy position of the Progress Energy regulated utilities. In 2005, I was promoted to Manager of the Power Trading group. My role as manager included responsibility for the short-term capacity and energy position of the Progress Energy regulated utilities in the Carolinas and Florida.

In 2012, upon consummation of the merger between Duke Energy Corp. and Progress Energy, Progress Energy became Duke Energy Progress and I was named Managing Director, Trading and Dispatch. As Managing Director, Trading and Dispatch I was responsible for Power and Natural Gas Trading and Generation Dispatch on behalf of Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I assumed my current position in November 2019.

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

A. Yes. I testified in support of DEC's 2020 fuel and fuel-related cost recovery application in Docket No. E-7, Sub 1250 and in DEP's 2020 fuel and fuel-related cost recovery application in Docket No. E-2, Sub 1272.

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, 2021 through December 31, 2021 ("test period") versus the period January 1, 2020 through December 31, 2020 ("prior test period"), and describe changes projected for the billing period of September 1, 2022 through August, 31 2023 ("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 Verderame Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Verderame 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 Verderame Confidential Exhibit 3, which summarizes the annual fuels related transactional activity between DEC and Piedmont Natural Gas Company, Inc. ("Piedmont") for spot commodity transactions during the test period, as required by the Merger Agreement between Duke Energy and Piedmont.

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 Verderame Exhibit 1.

Q. PLEASE DESCRIBE THE COMPANY'S APPROACH TO UNIT COMMITMENT AND DISPATCH OF ITS GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS.

A. Both DEC and DEP perform the same detailed daily process to determine the unit commitment plan that economically and reliably meets the Company's projected system needs over the next seven days. The Company utilizes a production cost model to determine an optimal unit commitment plan to economically and reliably meet system requirements. The model minimizes the production costs needed to serve the projected customer demand within reliability and other system constraints over a period of time. Inputs to the model include, but are not limited to, the following: (1) forecasted customer energy demand; (2) the latest forecasted fuel prices, reflective of market supply chain dynamics; (3) variable transportation rates; (4) planned maintenance and refueling outages at the generating units; (5) generating unit performance parameters; (6) reliability constraints such as units run to maintain day-ahead planning reserves or units required to run for transmission or voltage support; and (7) expected market conditions associated with power purchases and off-system sales opportunities. The production cost model output produces the optimized hourly unit commitment plan for the 7-day forecast period. This unit commitment plan also provides the starting point for dispatch, but dispatch is then also subject to real time adjustments due to changing system conditions including management of natural gas transportation constraints. The unit commitment plan is prepared daily and adjusted, as needed, throughout any given day to respond to changing real time system conditions.

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 $78.22 per ton, compared to $90.53 per ton in the prior test period, representing a decrease of approximately 14%. The cost of delivered coal includes an average transportation cost of $ 31.68 per ton in the test period, compared to $35.07 per ton in the prior test period, representing a decrease of approximately 10%. The Company's average price of gas purchased for the test period was $4.22 per Million British Thermal Units ("MMBtu"), compared to $2.94 per MMBtu in the prior test period, representing an increase of approximately 44%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEC's coal burn for the test period was 5.3 million tons, compared to a coal burn of 5.9 million tons in the prior test period, representing a decrease of 9 %. The Company's natural gas burn for the test period was 189.6 million MBtu, compared to a gas burn of 135.4 million MBtu in the prior test period, representing an increase of approximately 40%.

Changes in coal and natural gas burns were primarily driven by increased demand from the economic rebound experienced following the COVID-19 shutdowns in 2020. Rapidly escalating coal commodity prices in the latter half of 2021 off-set the overall increase in natural gas prices reducing gas to coal switching. Gas burns are also impacted by the inclusion of natural gas generation at Belews Creek Unit 2 and Marshall Units 3 & 4 as a result of the dual fuel conversions being commercially available in early 2021.

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

A. Coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers following the past several years of steep declines in coal generation demand, which has impacted the ability of producers to respond to changes in demand during 2021; (2) natural gas price volatility; (3) renewed uncertainty from the new administration regarding proposed and imposed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) increased demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening access to investor financing coupled with deteriorating credit quality is increasing the overall costs of financing for coal producers; (7) continued shifts in production from thermal to metallurgical coal as producers move away from supplying declining electric generation to take advantage of increasing demand from industry; and, (8) increasing labor and resource constraints due to structural changes in the coal industry further limiting suppliers' operational flexibility. In addition, the coal supply chain experienced increasing challenges throughout 2021 as historically low utility stockpiles combined with rapidly increasing demand for coal, both domestically and internationally, made procuring additional coal supply increasingly challenging. Producers were unable to respond to this rapid rise in demand due to capacity constraints resulting from labor and resource shortages. These factors combined to drive both domestic and export coal prices in 2021 to record levels.

Declining demand for coal in the utility sector has also driven rail transportation providers to modify their business models to be less dependent on coal related transportation revenues. Although rail transportation providers are required to provide rail service, the Company's rail transportation providers have limited resources to adapt to significant changes in scheduling demand resulting from the Company's burn volatility, specifically in higher than forecasted coal burn scenarios. In 2021, the Company experienced increased delivery delays created by rail transportation labor and resource shortages.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years as producers enhanced production techniques, enhance efficiencies, and lowered production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in

2021, such dynamics were influenced primarily by growth in export demand, stable production, lower than average storage inventory balances and seasonal weather demand. While there continues to be adequate natural gas production capacity there is a growing need for natural gas pipeline infrastructure to serve increased market demand. Conversely, pipeline infrastructure permitting and regulatory process approval efforts are increasingly challenged and taking longer due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing. The Federal Energy Regulatory Commission ("FERC") is in the process of developing policy for additional project requirements to include an analysis of environmental and social impacts on new pipeline infrastructure.

Over the longer term planning horizon, natural gas supply has the ability to respond to changing demand while the pipeline infrastructure needed to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico is highly uncertain.

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 3.3 million tons, compared to 5.3 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 $91.89 per ton for the billing period compared to $78.22

per ton in the test period. This increase in delivered costs is primarily driven by increased coal commodity costs due to limited coal supply and increased domestic and international demand. This includes an average projected total transportation cost of $29.63 per ton for the billing period, compared to $31.68 per ton in the test period. 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 Central Appalachian coal DEC is able to purchase and deliver and the non-Central Appalachian coal DEC is able to consume; (3) changes in transportation rates; (4) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; 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 242.0 million MBtu, which is an increase from the 189.6 million MBtu 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 primarily driven by coal to gas switching as a result of coal prices increasing more than gas as well as forecasts for less expensive gas supply to come into the portfolio early in the billing period. The current average forward Henry Hub price for the billing period is $$3.60 per MMBtu, compared to $3.84 per MMBtu in the test period.

The Company now expects projected natural gas burn volumes to be reduced based on delays in anticipated lower cost gas supply coming into the portfolio.

Projected natural gas burn volumes will also vary 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 ENSURE A COST-EFFECTIVE RELIABLE FUEL SUPPLY?

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. Additionally, the Company negotiates coal transportation contracts that support secure, reliable deliveries in a lower coal burn environment.

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. 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.

Lastly, DEC procures long-term firm interstate and intrastate transportation to provide natural gas to their generating facilities. Given the Company's limited amount of contracted firm interstate transportation, the Company purchases shorter term firm interstate pipeline capacity as available from the capacity release market. The Company's firm transportation ("FT") provides the underlying framework for the Company to manage the natural gas supply needed for reliable cost-effective generation. First, it allows the Company access to lower cost natural gas supply from Transco Zone 3 and Zone 4 and the ability to transport gas to Zone 5 for delivery to the Carolinas' generation fleet. Second, the Company's FT allows it to manage intraday supply adjustments on the pipeline through injections or withdrawals of natural gas supply from storage, including on weekends and holidays when the gas markets are closed. Third, it allows the Company to mitigate imbalance penalties associated with Transco pipeline restrictions, which can be significant. The Company's customers receive the benefit of each of these aspects of the Company's FT: access to lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties.

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

A. Yes, it does.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH THE COMPANY.

A. My name is John A. Verderame. My business address is 526 South Church Street, Charlotte, North Carolina 28202. I am employed as 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. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN SUPPORT OF THE COMPANY'S APPLICATION IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony and recommendations of Mr. Gregory Lander filed on behalf of Sierra Club as it relates to DEC's natural gas hedging and forecasting processes.

Q. WHAT IS THE PURPOSE OF THIS PROCEEDING?

A. It is my understanding that the purpose of this fuel proceeding is to obtain Commission approval of the Company's proposed fuel rates pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55.

Q. HAS ANY PARTY RECOMMENDED AN ADJUSTMENT TO THE FUEL RATES PROPOSED BY THE COMPANY?

A. No.

Q. PLEASE PROVIDE YOUR GENERAL RESPONSE TO THE TESTIMONY OF SIERRA CLUB WITNESS GREGORY LANDER.

A. Witness Lander and I agree that natural gas prices are "volatile and are subject to domestic – and increasingly, international– supply and demand factors."[1] We also seem to agree, at a high level, that in addition to normal supply and demand pressures recent factors such as the energy crisis in Europe and gas producers lack of production response could continue to put upward pressure on gas prices in the near term. Finally, we agree that hedging does "help reduce volatility and to stabilize prices for a portion of…generation fuel supply"[2] and that customers experienced the benefits, not only over the test period, but in the estimated billing period as well. In fact, for the review period, the Company hedged nearly 50% of its actual natural gas volumes resulting in a total savings of approximately $114M. The Company's billing period estimates are also inclusive of the Company's forward hedging positions in place at the time the estimate is calculated. Accordingly, my testimony briefly discusses the Company's financial natural gas hedging program as well as its physical hedging approach in response to Witness Lander's testimony on these topics. Witness Lander also discusses the Company's approach to forecasting but does

[1] Direct testimony of Gregory M. Lander, pg. 8, lines 23 & 24
[2] Lander Direct, pg. 11, lines 8 & 9

not make any recommendation that is germane to the purpose of this proceeding.

Q. HAS THE COMPANY PROVIDED SUFFICIENT INFORMATION IN THIS PROCEEDING TO ESTABLISH THAT ITS BILLING PERIOD ESTIMATES WERE REASONABLE AND PRUDENTLY FORECASTED, INCLUDING THAT INFORMATION THAT IS REQUIRED UNDER APPLICABLE LAW?

A. Yes. The content and structure of the Company's application in this proceeding conforms with North Carolina General Statutes ("N.C. Gen. Stat.") § 62-133.2(c) and (d) and Commission Rule R8-55, including the specific information required to be included in a fuel rider application under Rule R8-55(e) and is substantially identical to that of all recent fuel rider applications. Furthermore, no party has alleged that the Company's fuel application failed to conform to applicable law. Compliance with the Commission's clear and objective information requirements is the appropriate standard for evaluating the sufficiency of the Company's application.

Q. WHAT WERE THE COMMISSION'S CONCLUSIONS IN REGARD TO PREVIOUS ADDITONAL REPORTING RECOMMENDATIONS IN THE 2020 DEC AND DEP FUEL PROCEEDINGS?

A. The Commission rejected the recommendation of the Sierra Club witness in the 2020 fuel proceedings for DEC and DEP. Specifically, in the DEP fuel order, the Commission confirmed "that the sufficiency of the Company's fuel application should be evaluated based on the requirements of applicable law."[3] The Commission further noted that it had previously rejected similar recommendations from the Sierra Club witness and observed that "the scope and level of detail contained in the Company's application, testimony, exhibits, and workpapers as filed in this proceeding conforms with applicable law and is consistent with prior applications."[4] The Commission has rejected similar recommendations from a Sierra Club witness in the two recent fuel proceedings and should, for the same reasons, reject the recommendation of the Sierra Club witness in this proceeding.

Q. PLEASE RESPOND TO WITNESS LANDER'S RECOMMENDATION THAT THE COMPANY SHOULD USE WIND AND SOLAR ENERGY TO THE FULLEST EXTENT POSSIBLE TO HEDGE AGAINST FOSSIL FUEL PRICE VOLATILTY, INCLUDING BUILDING ADDITIONAL UTILITY SCALE WIND AND SOLAR FACILITIES.

A. There is no basis under applicable law to suggest that a fuel rider proceeding is the appropriate forum in which to evaluate inclusion of utility scale wind and solar generation into the Company generating mix. This recommendation should be completely disregarded.

II. NATURAL GAS FUEL HEDGING

Q. PLEASE DESCRIBE GENERALLY THE COMPANY'S APPROACH TO FUEL HEDGING.

---

[3] Order Approving Fuel Charge Adjustment, Docket No. E-2, Sub 1250 (November 30, 2020), at 12-13.
[4] *Id.* at 13.

A. The Company uses a phased hedging approach where financial hedges are executed over time for a percentage of the Company's forecasted natural gas burns. The strategy includes utilizing fixed price financial instruments including fixed price swaps and cost-less collar options to hedge price exposure to natural gas markets on a rolling 60-month period. DEC maintains target hedge percentages for each of the 12-month periods within the rolling 60-month period. The volumes hedged over time represent a portion of DEC's forecasted burns with higher hedging targets in the first 12 to 24 months and lower hedging targets in the 36 to 60-month period. The actual hedge percentage positions can change as commodity price relationships between coal and natural gas impact the economic dispatch order, but the hedge targets provide a framework for executing a layered hedging strategy. DEC's multi-year rolling approach to executing fixed price transactions for a portion of projected natural gas burns over time provides a reasonable and prudent approach to mitigate price volatility in the uncertain fuel markets. This strategy also allows DEC more flexibility to adjust hedging volumes to accommodate changes in its forecasted natural gas consumption that will occur as market conditions change.

Q. DOES THE COMPANY REVIEW AND UPDATE ITS HEDGING PROGRAM AS A RESULT OF CHANGING MARKET CONDITIONS?

A. The Company continuously evaluates its hedging program to ensure that it remains appropriate based on market conditions and the Company's strategy. In late 2020 the Company extended its hedging program from 36 months to 60 months to mitigate customers exposure to future upward pressure on U.S. market prices as the Company's forecasted gas usage continued to grow over time. During its review in 2021, the Company further increased the hedging target ranges for the periods 25 to 60 months by an additional five percent as this higher percentage in the outer periods continues to decrease gas price exposure and smooth the transition from one hedging period to another as the outer periods move closer to prompt.

Q. DOES THE COMPANY ENGAGE IN ANY PHYSICAL HEDGING OF NATURAL GAS SUPPLY?

A. Yes. As an example, to reduce exposure to Transco Zone 5 monthly and daily prices, the Company contracts for optional physical natural gas supply through monthly calls and daily optimization of its physical gas storage. The Company can call on these products to be utilized when generation is needed to meet system demand. Additionally, following a review of the physical hedging program in late 2014, the Company increased its percentage of base load first of the month fixed price gas purchased to supply its combined cycle generation in order to mitigate the risk of daily gas price spikes.

III. PROPOSED FORECASTING REQUIRMENT

Q. HAS THE COMPANY REVIEWED ITS FORECASTING PROCESS TO EVALUATE THE RISK OF SIGNIFICANT UNDER-RECOVERY OF FUEL COSTS FROM CHANGING NATURAL GAS PRICES?

A. Yes. Following the North Carolina Utilities Commission ("NCUC") Order Approving Fuel Charge Adjustment ("2019 Fuel Order") in Docket No. E-7, Sub 1190, directing the Company to "evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs and report the results of that evaluation in the Company's next fuel proceeding," the Company conducted a review and filed the results in Docket No. E-7, Sub 1228.

Q. WHAT WERE THE RESULTS OF THE REVIEW?

A. In summary, the Company reviewed both its fuel forecasting and physical hedging methodology and "determined that no adjustments were needed to its current method of forecasting or to its physical hedging program…The Company also recommend[ed] extending financial hedging activities for a lower percentage in rolling years four and five to mitigate costs risks for customers."[5] The results were laid out in NCUC Order Approving Fuel Charge Adjustment in Docket No. E-7, Sub 1228 under the evidence and conclusions for Finding of Fact No. 5. Finding of Fact No. 5 states "The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent."[6]

Q. DURING THIS REVIEW, DID THE COMPANY CONSIDER AN APPROACH SUCH AS WITNESS LANDER'S RECOMMENDATION OF INCORPORATING PERIODIC GAS PRICE SPIKES INTO ITS FORECASTED FUEL COSTS?

A. The Company performed a review of its forecasting method and historical natural gas price fluctuations to determine if adjustments, including those similar to Witness Lander's recommendation, would be warranted to mitigate the risk of significant under recoveries. Following this review the Company found that: 1) the observed natural gas market prices utilized for the applicable

---

[5] Order Approving Fuel Charge Adjustment, Docket No. E-7, Sub 1228 (August 19, 2020), at 12-13.
[6] *Id.* at 4.

forecast are the market forward Henry Hub prices and observed locational basis that are observed in the market at the time the forecast is prepared and represents the best estimate of forecasted prices at that time; 2) mild weather or an extreme winter weather event and corresponding impacts to the balance of supply and demand were a significant driver of differences in the actual market natural gas prices from those utilized in the applicable forecast; 3) weather trends over a season or short-term extreme weather events and their corresponding impacts to the balance of supply and demand are not known and cannot be fully predicted nor forecasted without introducing significant speculation into the forecasting process; and, 4) given the time lag between the forecast and the end of the applicable billing period, numerous changes will occur between the actual outcomes versus the inputs that existed at the time of the forecast. Only with the benefit of hindsight could inputs such as actual weather events, prices, and system cost impacts be known. Additionally, the forward natural gas market curves that are incorporated into the Company's fuel forecasts at any point in time represent what is known about supply and demand and are reflective of supply and demand dynamics and trends. Currently, forward market prices reflect tightening supply and demand fundamentals. Tight supply and demand fundamentals are expected to remain until there is a responsive increase in natural gas production or a decrease to demand due to factors such as but not limited to mild weather trends or other economic shifts that could result in lower consumption.

Therefore, in the Company's view, incorporating historical high market price events or other speculative forecasting assumptions into the Company's current forecasting processes to potentially mitigate large under-recoveries is speculative and could arbitrarily increase forecasted costs billed to customers with the unwanted consequence of more consistent over-recoveries over the long-term.

Q. HAS THE COMPANY CONSIDERED INCORPORATING ANY CHANGES THAT COULD PROVIDE THE COMPANY WITH ADDITIONAL FORECASTING MODELING CAPABILITIES?

A. Yes. Beginning in 2020, the Company began incorporating the outputs of its Fleet Analytics Stochastic Tool "FAST" model into its fuel planning, procurement, and hedging processes for 2021 and beyond. The Company continues to review additional opportunities to expand the use of stochastic production cost modeling and related outputs into its overall forecasting process to better calculate the range of costs that could occur throughout the forward period.

Q. PLEASE EXPLAIN THE MODEL CHANGES UTILIZING STOCHASTIC CAPABILITIES.

A. In summary, the stochastic production cost model uses historical weather information to simulate numerous iterations or scenarios of future weather and load. For each of these iterations, system load and commodity prices (gas, coal, oil, and power) are all calculated in a correlated manner using historical correlations with each other and with weather. For example, if in a simulated iteration winter is particularly cold, then that iteration would have higher load and higher gas and power prices. It should be noted that the average of all simulated commodity prices matches the underlying market forward price while providing a range of daily prices that can occur throughout forward periods. The resulting forecasts produced from the stochastic production cost model give the Company not only expected fuel burns, but also the probability associated with various ranges of fuel burns.

Q. PLEASE COMMENT GENERALLY ON THE PURPOSE OF THIS PROCEEDING AS IT RELATES TO THE TESTIMONY OF SIERRA CLUB WITNESS LANDER.

A. Once again, the purpose of this proceeding is to establish fuel rates for DEC. Witness Lander has not recommended any changes to the fuel rates proposed by DEC. Instead, witness Lander has sought to leverage this proceeding into an opportunity to opine on a number of topics that are either properly addressed in other proceedings, some currently open, or have previously been rejected by the Commission. In the Company's view, such efforts are not an efficient use of regulatory resources.

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

A. Yes, it does.

BY MR. KAYLOR:

Q Do you have a summary of your direct and rebuttal testimony?

A I do.

Q Please proceed to give that to the Commission.

A (Mr. Verderame) Chair Mitchell, Commissioners, good morning.

(WHEREUPON, the summary of JOHN A. VERDERAME is copied into the record as read from the witness stand.)

DUKE ENERGY CAROLINAS, LLC
JOHN VERDERAME'S DIRECT AND REBUTTAL TESTIMONY SUMMARY
DOCKET NO. E-7, SUB 1263

In my direct testimony I described DEC's fossil fuel purchasing practices, provided actual fossil fuel costs for the period January 1, 2021 through December 31, 2021 ("test period") versus the period January 1, 2020 through December 31, 2020 ("prior test period"), and described changes projected for the billing period of September 1, 2022 through August 31, 2023 ("billing period").

No party to this proceeding has filed testimony recommending a disallowance of any costs incurred by DEC.

In my rebuttal testimony, I respond to the testimony and recommendations offered by Mr. Gregory Lander on behalf of the Sierra Club. Witness Lander has not recommended any changes to the Company's proposed fuel rates and his testimony focuses on the recent volatility of natural gas prices. He suggests the Company should utilize a "physical hedge" to mitigate natural gas price volatility by building additional utility scale renewable energy facilities and he recommends certain changes to the Company's forecasting practices.

The Company agrees that natural gas prices are volatile and that is why the Company practices both financial and physical hedging. For the review period, the Company hedged nearly 50% of its actual natural gas volumes resulting in a total savings of approximately $114 million.

The content and structure of the Company's application in this proceeding conforms with North Carolina General Statutes ("N.C. Gen. Stat.") § 62-133.2(c) and (d) and Commission Rule R8-55, including the specific information required to be included in a fuel rider application under Rule R8-55(e) and is substantially identical to that of all recent fuel rider applications. Furthermore, no party has alleged that the Company's fuel application failed to conform to applicable law. The Commission has rejected similar recommendations from a Sierra Club witness in the two recent fuel proceedings and should, for the same reasons, reject the recommendation of the Sierra Club witness in this proceeding.

Witness Lander's testimony indicates that the Company should utilize a physical fuel hedge by building additional utility scale renewable energy facilities. The Company does not believe the fuel rider proceeding is the appropriate forum in which to evaluate the inclusion of utility scale wind and solar generation to the Company generation mix.

The Company uses a phased hedging approach where financial hedges are executed over time for a percentage of the Company's forecasted natural gas burns, with higher hedging targets in the first 12 to 24 months and lower hedging targets in the 36 to 60-month period. This multi-year rolling approach to executing fixed price transactions provides a reasonable and prudent approach to mitigate price volatility in uncertain fuel markets. In late 2020, the Company extended its hedging program from 36 months to 60 months to mitigate customers' exposure to future upward pressure on U.S. market prices. During its review of the program in 2021, the Company further increased the hedging target ranges for the periods of 25 to 60 months by an additional 5 percent to decrease gas price exposure and smooth the transition from one hedging period to another as the outer periods move closer to prompt. The Company also engages in physical hedging by contracting for optional physical natural gas supply through monthly calls and daily optimization of its physical gas storage to reduce exposure to Transco Zone 5 monthly and daily prices. The Company has also increased its percentage of base load first of the month fixed price gas purchased to supply its combined cycle generation in order to mitigate the risk of daily gas price spikes.

With respect to Witness Lander's recommendation that the Company incorporate periodic gas price spikes into its forecasted fuel costs, the Company has reviewed its forecasting process, including an evaluation of approaches similar to Witness Lander's recommendation, and determined such a change is unwarranted. Only with the benefit of hindsight could inputs such as actual weather events, prices, and system cost impacts be known. Additionally, the forward natural gas market curves that are incorporated into the Company's fuel forecasts are reflective of supply and demand dynamics and trends. In the Company's view, incorporating historical high market price events and other speculative forecasting assumptions into the current forecasting process could arbitrarily increase forecasted costs billed to customers with the unwanted consequence of more consistent over-recoveries over the long-term. Additionally, beginning in 2020 the Company has incorporated the outputs of its Fleet Analytics Stochastic model into its fuel planning, procurement, and hedging processes. The Stochastic production cost model uses historical weather information to simulate numerous iterations or scenarios of future weather and load. This gives the Company not only expected fuel burns but also the probability associated with various ranges of fuel burns. The Company continues to review additional opportunities to expand the use of stochastic production cost modeling and related outputs into its overall forecasting process to better calculate the range of costs that could occur throughout the forward period.

The purpose of this proceeding is to establish fuel rates for DEC. Witness Lander has not recommended any changes to the fuel rates proposed by DEC but instead has sought to leverage this proceeding into an opportunity to opine on a number of topics that are either properly addressed in other proceedings, some currently open, or have previously been rejected by the Commission.

This concludes my direct and rebuttal testimony summary.

BY MR. KAYLOR:

Q Thank you, sir. Mr. Sykes, state your name and business address for the record, please.

A My name is Bryan L. Sykes. And my business address is 526 South Church Street in Charlotte, North Carolina.

Q And by whom are you employed and in what capacity?

A I am employed by Duke Energy Carolinas as Director of Rates and Regulatory Filings.

Q In preparation for this hearing, did you have direct testimony consisting of 17 pages and six exhibits prepared?

A Yes, I did.

Q And did you also prepare supplemental testimony consisting of five pages?

A Yes, I did.

Q And I believe you had four revised exhibits to that supplemental testimony; is that correct?

A That is correct.

Q Do you have any changes or corrections to your direct or supplemental testimony?

A Yes. I have two changes to my direct testimony. On page 15 of my direct testimony, line 7, the first word states "decrease". That should be replaced with "increase". And on line 10, one of the last words is the "EMF decrement rate". That should be replaced with "EMF increment rate".

Q Thank you.

MR. KAYLOR: At this time, Madam Chair, I would ask that Mr. Sykes' direct and supplemental testimony be introduced into the record as if given orally and his six exhibits and four revised exhibits be identified as marked.

CHAIR MITCHELL: Hearing no objection to that motion, I will allow it. The direct and supplemental testimony of the witness shall be copied into the record as if delivered orally from the stand. The exhibits shall be marked as they were for identification purposes as they were when prefiled.

MR. KAYLOR: Thank you.

(WHEREUPON, Sykes Exhibits 1-6, Workpapers 1-13 Revised Exhibits 1-4, Exhibit 5, Exhibit 6, Revised Schedule 10, Revised Workpapers 7, 10, 12 and 13 are marked for identification as prefiled.)

(WHEREUPON, the prefiled direct and supplemental testimony of BRYAN L. SYKES is copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF BRYAN L. SYKES 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 Bryan L. Sykes. My business address is 526 South Church Street, Charlotte, North Carolina.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received my Bachelor of Science and Master of Science Degrees in Accounting from East Carolina University. I am a certified public accountant licensed in the State of North Carolina. I began my career in 2001 with Arthur Andersen, LLP as a staff auditor. From 2001 until 2006 I held various roles in public accounting firms, including Grant Thornton, LLP (successor to Arthur Andersen, LLP) and subsequently PricewaterhouseCoopers, LLP. In 2006, I began working at Progress Energy, Inc. as a financial auditor and subsequently held a variety of positions in the accounting organization before and after the merger with Duke Energy Corporation in 2012. I joined the Rates Department in 2019 as Manager, Rates and Regulatory Filings and recently became Director, Rates and Regulatory Planning.

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

A. I am responsible for providing regulatory support for retail rates, 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 most recently provided testimony in last year's annual fuel proceeding for DEC in Docket No E-7, Sub 1250.

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 Sykes 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, 2021 ("test period"), and the billing period is September 1, 2022 through August 31, 2023 ("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 SYKES 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 93.94% proposed nuclear capacity factor and projected megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 93.94% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 92.07% 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 2021 Monthly Fuel Reports.

1) December 2021 Monthly Fuel Report required by NCUC Rule R8-52.

2) December 2021 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

Q. PLEASE EXPLAIN SYKES EXHIBIT 1.

A. Sykes 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 2.3100¢, 2.3198¢, and 2.3139¢ per kWh, respectively, to be reflected in rates during the billing period. The factors DEC proposes in this proceeding incorporate a 93.94% nuclear capacity factor as testified to by Company witness Capps, projected fossil fuel costs as testified to by Company witness Verderame, projected nuclear fuel costs as testified to by Company witness Houston, and projected reagents costs as testified to by Company witness Walsh. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Sykes 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	1.9315	1.8573	1.9011	1.9011
EMF Increment (Decrement)	0.3785	0.4625	0.4128	0.4191
EMF Interest (Decrement)	-	-	-	-
Net Fuel and Fuel Related Costs Factors	2.3100	2.3198	2.3139	2.3202

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 an 8.16% 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	2.3100	2.3198	2.3139	2.3202
Existing Total Fuel Factor	1.5014	1.7371	1.8634	1.6767
Increase in Fuel Factor	0.8086	0.5827	0.4505	0.6435

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 is primarily driven by a $245 million under-recovery in the current test period compared to a $20 million under-recovery included in current rates. The Company typically experiences some amount of over or under recovered fuel costs during the test period. The EMF provision of fuel rates was established to address the differences between fuel revenues realized and fuel costs incurred during a test period. Beginning around June 2021, a few months after the Company filed its proposed fuel rates on February 23, 2021, the Company experienced an unexpected increase in fuel commodity costs, as described in the direct testimony of Witness Verderame. For the test period months of June through December, the fuel revenues collected by DEC were materially less than the fuel costs incurred, resulting in a large under collection of costs, which is reflected in DEC's proposed EMF rates. In addition, estimated system fuel costs in the billing period are higher due to expected higher commodity prices.

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 SYKES 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 93.94% and provides the forecasted MWh sales for the billing period on which system generation and costs are based. Forecasted generation and purchased power associated with the Company's CPRE Program, established by N.C. Gen. Stat § 62-110.8 and approved by this Commission in Docket No. E-7, Sub 1156, used to supply the Company's native load has been included in Exhibit 2, as part of total system costs to supply native load sales. Recovery of the purchased and generated power costs associated with CPRE generation and purchased power are included in the Company's Rider CPRE filing in Docket No. E-7, Sub 1262.

Schedule 2 also uses the proposed capacity factor of 93.94% 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 92.07%. This capacity factor is based on the 2016 through 2020 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 the final 2020 cost of service production plant allocators since the 2021 cost of service study is not available at the time of filing. When this allocator becomes known, DEC may elect to make a supplemental filing to adjust its proposed billing period rates, if the estimated rates are materially impacted.

Page 3 of Exhibit 2, Schedules 1, 2, and 3 shows the allocation of system fuel costs to the 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 SYKES 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 Sykes Exhibit 2, Schedule 1. For purposes of this filing, as a proxy for generation dispatch modeling, Sykes Exhibit 2, Schedules 2 and 3 adjust the coal generation produced by the dispatch model. For example, on Exhibit 2, Schedule 2, which is based on the proposed capacity factor and normalized test period sales, DEC decreased the level of coal generation to account for the difference between forecasted generation and normalized test period generation. On Exhibit 2, Schedule 3, which is based on the NERC capacity factor, DEC increased the level of coal generation to account for the decrease in nuclear generation. The decrease in nuclear generation results from assuming a 92.07% NERC nuclear capacity factor compared to the proposed 93.94% nuclear capacity factor.

Q. SYKES 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. Sykes 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 $86.9 million, $107.3 million and $50.7 million respectively. There is one adjustment included in the calculation of the under-recovery balance at December 31, 2021. This adjustment relates to the months of January and February 2021, which were included in the fuel rate approved in the last fuel and fuel-related cost recovery proceeding and is included for Commission review in the current proceeding. The Company has excluded the amount of under-recovery for the months of January and February 2021 that was included in the EMF approved in Docket E-7, Sub 1250 when computing the proposed EMF factors.

The (over)/under recovery 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 the 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.

The Company typically experiences some amount of (over)/under recovery of fuel costs during the test period. The EMF provision of fuel rates was established to address the differences between fuel revenues realized and fuel costs incurred during a test period. Beginning around June 2021, a few months after the Company filed its proposed fuel rates on February 23, 2021, the Company experienced an unexpected increase in fuel commodity costs, as described in the direct testimony of Witness Verderame. For the test period months of June through December, the fuel revenues collected by DEC were materially less than the fuel costs incurred, resulting in a large under collection of costs, which is reflected in DEC's proposed EMF rates.

Q. PLEASE EXPLAIN SYKES EXHIBIT 4.

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Sykes 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 1214) and used in its last fuel proceeding. Sykes Exhibit 4 also sets forth actual test period fuel-related revenue and fuel expense on a total DEC basis and for North Carolina retail. The test period peak demand data for the system and for NC retail customer classes, typically included on Exhibit 4, is not available at the time of this filing. The Company will make a supplemental filing to update Exhibit 4 to include this data when it becomes available.

Q. PLEASE EXPLAIN SYKES EXHIBIT 5.

A. Sykes 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 Sykes Exhibit 6, DEC's test year actual fuel and fuel-related costs were 2.1273¢ 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) the high capacity factors of its nuclear fleet; and (3) 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 Walsh discusses the performance of the fossil and hydro fleet, as well as the use of chemicals for reducing emissions. Company witness Verderame 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), (6), (10) and (11) of N.C. Gen. Stat. § 62-133.2(a1). Subdivisions (4), (6), (10) and (11) address purchased power non-capacity costs. Subdivisions (5), (6), (10) and (11) address purchased power capacity costs. The allocation methods for these costs are as follows:

(a) Capacity-related purchased power costs in Subdivisions (5), (6), (10) and (11) are allocated based upon the final 2020 cost of service production plant allocators since the 2021 cost of service study is not available at the time of filing. During the billing period, when DEC computes its actual fuel costs for comparison to fuel revenues realized, DEC will use the appropriate production plant allocator from the 2021 cost of service study in determining North Carolina retail's share of actual costs by customer class. In addition, when this allocator becomes known, DEC may elect to make a supplemental filing to adjust its proposed billing period rates, if the estimated rates are materially impacted.

(b) Non-capacity related purchased power costs in Subdivisions (4), (6), (10) and (11) 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 the 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 2021 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1250.

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

A. Sykes 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 8.16% was calculated by dividing the fuel and fuel-related cost increase of $374,738,584 for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $4,591,210,481. The cost increase of $374,738,584 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 decrease 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 Sykes Exhibit 2, Schedule 1) and the proposed composite EMF decrement rate (as computed on Sykes Exhibit 3, page 1). This results in a uniform bill percentage change of 8.16% Sykes 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 SYKES EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. Sykes 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 Sykes 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 period sales for each class (either projected billing period or adjusted test period) 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 Sykes Exhibit 3, Page 2, 3, and 4) to derive the prospective component for each customer class. This breakdown is shown on Sykes 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), (6), (10) AND (11) 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 WORK PAPERS 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.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**SUPPLEMENTAL TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF BRYAN L. SYKES 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 Bryan L. Sykes. My business address is 526 South Church Street, Charlotte, North Carolina.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes, on March 1, 2022, I caused to be pre-filed with the Commission my direct testimony and 6 exhibits and 13 supporting workpapers.

Q. YOUR SUPPLEMENTAL TESTIMONY INCLUDES FOUR (4) REVISED EXHIBITS AND FOUR (4) REVISED SUPPORTING WORKPAPERS. WERE THESE SUPPLEMENTAL EXHIBITS AND WORKPAPERS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

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

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

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

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

Sykes Revised Exhibit 4: Sales, Fuel Revenue, Fuel Expense and System Peak

Sykes Revised Workpapers 7 and 7b: Calculation of Allocation Percentages Based on Projected Period Sales

Sykes Revised Workpaper 7a: Calculation of Allocation Percentages Based on Normalized Test Period Sales

Sykes Revised Workpaper 10: 2.5% Calculation Test

Sykes Revised Workpaper 12: Weather Normalization Adjustment

Sykes Revised 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 revised rates reflecting the impacts related to four updates to numbers presented in my direct exhibits.

The first update relates to the proposed EMF increment for the experienced under-recovery of fuel and fuel-related costs, pursuant to NCUC Rule R8-55(d)(3), which allows the Company to incorporate the fuel and fuel-related cost recovery balance up to thirty (30) days prior to the hearing. The Company elects this option and supplements the direct testimony and exhibits to include the fuel and fuel-related cost recovery balance as of the 11 months ended January 31, 2022.

The second update revises the production plant allocator used to allocate renewable and purchased power capacity costs to the North Carolina Retail jurisdiction. In my direct testimony, I indicated that the 2021 cost of service study was not available at the time of filing. Since then, the Company has prepared the cost of service study, and the 2021 production plant allocator has been incorporated into this supplemental filing. The impact of this update, by itself, lowers customer rates.

The third update revises the coincidental peak data reported on Exhibit 4, which was not available in the Company's direct filing. The coincidental peak data is informational and has no impact on proposed rates.

The fourth update relates to a revision in the retail customer growth adjustment and the wholesale weather adjustment. The retail customer growth adjustment update was required to reflect the actual number of customers more accurately within the test period. This adjustment increases the EMF rate proposed on Exhibit 3, which uses normalized test period sales, while the wholesale weather adjustment does not impact proposed rates. In addition, the impact of this update revises one of the fuel rate scenarios presented in my direct filing. The scenario based on the proposed nuclear capacity factor and normalized test period sales is updated to reflect the retail customer growth and wholesale weather adjustments on Exhibit 2, Schedule 2.

Q. HOW DID THE FUEL AND FUEL-RELATED COST RECOVERY BALANCE CHANGE IN THE ONE (1) MONTH BEING INCORPORATED?

A. The Company experienced an under-collection of $81,987,600 in January 2022. As shown on Sykes Revised Exhibit 3, the incorporation of the update period under-collection balance resulted in an under-recovered balance of $326,974,214.

Incorporating the under-collection experienced in January 2022 will increase the EMF increment rate charged to all customer classes.

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

A. The NC Retail Total Fuel Costs were increased by $81,819,379 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 Sykes Revised Exhibit 1, are as follows:

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Total adjusted Fuel and Fuel Related Costs	2.0003	1.8217	1.8396	1.9010
EMF Increment (Decrement)	0.4863	0.6254	0.5726	0.5597
EMF Interest Increment (Decrement)	-	-	-	-
Net Fuel and Fuel Related Costs Factors	2.4866	2.4471	2.4122	2.4607

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 9.94% increase on customers' bills, as compared to the previously filed increase of 8.16%.

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

A. Yes, it does.

BY MR. KAYLOR:

Q Mr. Sykes, do you have a summary of your direct and supplemental testimony?

A Yes, I do.

Q Please proceed.

A Good morning, Chair Mitchell and Members of the Commission.

(WHEREUPON, the summary of BRYAN L. SYKES is copied into the record as read from the witness stand.)

DUKE ENERGY CAROLINAS, LLC
BRYAN L. SYKES DIRECT and
SUPPLEMENTAL DIRECT TESTIMONY SUMMARY
DOCKET NO. E-7, SUB 1263

The purpose of my testimony is to present the information and data required by North Carolina General Statutes § 62-133.2(c) and (d) and Commission Rule R8-55, as set forth in Sykes 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, 2021 ("test period"), and the billing period is September 1, 2022 through August 31, 2023 ("billing period").

In my supplemental testimony, I present revised rates reflecting the impacts related to four updates to numbers presented in my direct exhibits.

The primary update relates to incorporating into the Experience Modification Factor ("EMF") increment, the under-recovered fuel and fuel-related costs experienced during the month of January 2022. Following the incorporation of the update period, the North Carolina Retail under-recovered balance as of January 31, 2022 is approximately $327 million dollars. This update has been reflected in my supplemental testimony and in the proposed rates conveyed in this summary.

In addition, the supplemental testimony included the following updates: (1) a revised, final production plant allocation factor used to allocate renewable and purchased power capacity costs to the North Carolina Retail jurisdiction, (2) the final 2021 coincidental peak data, and (3) revisions to the retail customer growth and wholesale weather megawatt hour adjustments.

The impact of all updates made in supplemental testimony was an increase to NC Retail total fuel costs of $81,819,379. This amount is primarily related to the incorporation of January 2022's under-recovered fuel and fuel-related costs of $81,987,600.

Following these updates, the net proposed fuel and fuel-related costs factors by customer class are: 2.4866 cents/kWh for Residential customers, 2.4471 cents/kWh for General Service customers and 2.4122 cents/kWh for Industrial customers.

This concludes a summary of my testimony.

BY MR. KAYLOR:

Q Thank you, Mr. Sykes.

MR. KAYLOR: With the Chair's permission, I do have a few additional direct questions for Mr. Sykes, and I did pass those out to the parties earlier in this proceeding.

CHAIR MITCHELL: I'll let you go ahead, Mr. Kaylor, and then I'll give the parties an opportunity to cross should there be any.

MR. KAYLOR: Thank you.

BY MR. KAYLOR:

Q Mr. Sykes, why did the Company make a supplemental fuel filing to increase its proposed rates in this proceeding?

A So, after reviewing the Company's under-recovery for the period beginning January '22 through March '22, the Company discussed its appetite for making a supplemental fuel filing internally and initially decided not to make a supplemental fuel filing, leaving the proposed increase at 8.16 percent. Leading up to the deadline for intervenor testimony, the Company had several discussions with the Public Staff about the Q1 continued under-recoveries and the latest forecasted under-recoveries for the remainder of calendar year 2022. In an effort to avoid a larger, more significant under-recovery in the 2023 fuel proceeding, the Company agreed to include an approximate $82 million under-recovery for January '22 only in the Company's supplemental fuel filing. The inclusion of this under-recovery kept the total customer impact to less than 10 percent and kept fuel rates below the 2009 approved rates. 2008 was another year where we had significant fuel costs and fuel costs were volatile.

There is never a good time to ask our customers to pay more for electricity needs; however, we are in somewhat unprecedented times with fuel price volatility, and informing customers of real-time rates is important today, particularly as the Company expects fuel prices to remain at elevated levels during 2022 and possibly beyond. Ultimately, this Commission has the final approval of the Company's proposed rates.

Q So, what customer impacts result from the

Company's proposed new rates?

A Our residential customers using 1,000 kWh would see an approximate $10.00 per month; smaller commercial customers would see an approximate $102.00 increase per month; larger commercial customers would see an approximate $1,065.00 increase per month; and industrial customers would see an approximate $29,000 increase per month.

Q What are the costs associated with this supplemental fuel filing?

A The Company experienced an EMF, or true-up component, of $327 million. This represents approximately 72 percent of the "ask" for this proceeding. The remaining "ask" relates to an increased forecasted fuel cost of $130 million.

Q And what is the Company expecting during the 2022 test period?

A So, the Company submits monthly fuel reports to this Commission, and based on the fuel reports that have been filed for January through April of 2022, we are currently seeing an under-recovery of $182 million. Based on the latest forecast data we have, we expect to see approximately $228 million in total calendar year 2022 under-recoveries.

Q We've heard talk of the Company's hedging program, how did that benefit the customers during the year?

A The Company's hedging program during the 2021 test period realized savings of approximately $116 million on a system-wide basis. This translates into approximately $77 million of savings for our North Carolina retail customers. Additionally, as we are looking into the results for 2022, we have realized savings in January through April of 2022 of an additional $116 million which translates into another $77 million for North Carolina retail customers. I'll note that fuel prices began spiking in Spring of 2021, so the benefit in 2021 began increasing approximately May 2021. We are already seeing as much savings in 2022 since fuel prices continue to be significant, and they are rising. It's a coincidence these numbers are the same.

Q What forecast did the Company use in this proceeding?

A The Company used a forecast that began with fuel commodity prices as of the close of business December 9th, 2021. This was the forecast that was most recently available at the time of the fuel filing on March 1st, 2022. From the time a forecast close of business is set, it takes approximately two to three weeks to execute the forecast and another two weeks to determine customer rates.

Subsequent to the Company's direct filing, the Company obtained another forecast as of the close of business March 10th, 2022. This forecast showed an increase of 2.7 percent in total fuel costs.

Leading up to the Company's supplemental filing, we discussed this March 10th forecast and also looked at the under-recoveries through March 2022. In our supplemental filing, we elected to retain the December 9th forecast but include the January '22 under-recovery of $82 million.

Q And so what are the costs associated with this supplemental fuel filing?

A The Company experienced an EMF or true-up component of $327 million. This represents approximately 72 percent of the "ask" in this proceeding. The remaining "ask" relates to increased forecasted fuel costs of $130 million.

Q What is the Company expecting during the 2022 test period?

A Wait! There is an extra page in here. We just asked -- we just went through that.

Q I'm sorry. We just asked that one.

MR. KAYLOR: That should complete the additional direct questions. Thank you.

CHAIR MITCHELL: At this time, I'll check in with the parties to see if there is any cross examination for the witness on this direct testimony just given. Mr. Creech?

MR. CREECH: No questions.

CHAIR MITCHELL: Any other party?

MS. CRESS: No questions, Chair.

MR. SCHAUER: No questions.

MS. JONES: No questions.

MS. THOMPSON: No questions because I just heard this testimony and I didn't know that it was going to be presented, but thank you for the opportunity to ask questions.

CHAIR MITCHELL: Understood, thank you. Let me see if -- let me check in with Commissioners to see who has questions for the Company's witnesses on any of the testimony filed in this docket.

(No response)

I have a few questions. The Commission has a few questions for you. Let me get organized here.

EXAMINATION BY CHAIR MITCHELL:

Q Gentlemen, thank you both for being here this morning. I will take you through -- I have a few questions. Either or both may respond

So, you-all have testified about the under-recovery at issue in this proceeding and it's -- I think you just testified it's at about $300 plus million. When the Company realized the extent of the under-recovery, I'm assuming that that probably happened sometime last summer, did you-all think about coming in sooner or taking any other action to address the under-recovery as opposed to waiting for it to continue to grow?

A (Mr. Sykes) That's a great question. And I'm not an attorney but in looking at the North Carolina Fuel Statute, there's not an opportunity to come in before the Commission and seek some type of mid-course correction. So again, we do supply monthly fuel reports to the Commission, and the public can access those reports, and folks can see the growing under-recovery. But no, there was not an opportunity to come before the Commission to seek some type of mid-course correction.

Q So we -- you -- the Public Staff, we were all -- we were aware of the growing under-recovery, and this is the first point in time at which the Company could address that under-recovery?

A In my opinion, yes.

Q Anything, Mr. Verderame, to add?

A (Shakes head no)

Q Okay. So, the price of natural gas has continued to escalate over the course of the past -- over the test-year period as well as it continues to escalate. We understand from your direct testimony, Mr. Verderame, that the forward price for the billing period was $3.60, and Public Staff witnesses testify that as of May of 2022, this spring, it's been around 6.5 cents, and we know it's probably higher right now as we speak.

You've testified about the under-recovery that exists right now for the 2020 -- I guess it would be the next Fuel Rider proceeding and that it's growing. Are you -- and you've also given us in your testimony today sort of your best guess at where you think that under-recovery will be when it is time for you-all to come in. But is that -- you know, how confident are you in that opinion or in that testimony, given that the price of gas is higher now than it was obviously in December when you-all were preparing the filings for this proceeding, and it continues to escalate?

A (Mr. Verderame) I can start, Chair Mitchell. Thank you. So, when I used to work on Wall Street, we had an expression "If you show me tomorrow's newspaper you'd only see me tomorrow". So, unfortunately, the forward curve is our window into the future, and so the level of confidence I have is solely based on that forward look. But I will say if you've read one article on the drivers behind gas, you've probably read them all: Lack of production; response to the price; concern about storage and how that will impact, and I think that's important how that will impact future years; and then just demand domestically and internationally.

But the general read I think is the -- I think that what's somewhat broken in the normal price response to natural gas, and this leads up to why I think we're going to see volatility going forward. The normal response to price, high prices, is either production response or demand destruction. So, we've talked about the production response. I think the forward curve is giving some hesitancy to product producers to go out and put more holes in the ground. They're also feeling pressure from their long-suffering investors to return cash. So, I think it will take some time for production to return.

But on the demand destruction

side, that's usually where we see coal-to-gas pass the coal switching, right. And there's a whole nother discussion around the drivers behind coal and, effectively, there is very limited ability for generation to switch from gas to coal at this point. And so that's -- there's a limit to demand destruction.

The second demand destruction usually comes from utility use, I'm sorry, industrial use. And even at $7.00 to $8.00 gas, these industrial users are fairly competitive against international users of gas that are $20.00 or $30.00 a dekatherm. So that's not slowing down demand either.

And then, finally, oil. The last demand destruction comes from switching from gas to oil. And at oil, the current conflict in Ukraine is driving oil prices at $125.00 a barrel. That inflection point is now $30.00 a barrel -- $30.00 a dekatherm.

So, to answer your question is there's really not a lot of confidence here. I think because there's not a lot of stuff to slow down gas where we are right here, and I think that drives us to the short-term influences on gas, which will be the summer upcoming, and how will we refill storage heading into the next winter period.

Q Thank you for that testimony. And just to follow up with you a bit there, Mr. Verderame, in your material -- in your testimonies filed in this proceeding, you indicated that the Company plans to increase gas burn in the coming year and reduce coal burn. Some of that is a result of the -- several units coming offline. You noted that Allen had come offline. You note that there are planned retirements this year. And so with all of that in mind, how -- I want -- and I hear you saying that the numbers you are putting before us in this proceeding are subject to all of the external forces over which we have no control, the Company has no control. The Company does have control over how it procures fuel and operates its systems. So, assure me that the Company is going to do everything it can to insulate its customers from the volatility that we are experiencing now and are likely going to experience as we move forward?

A So, I will start off with I think of all the jurisdictions that I'm responsible for, the Carolinas have managed through this fuel crisis better than all the others, and I think it's a testament to two -- one -- two things. One, the portfolio of assets we have and the diversity of those assets to switch between fuels when that's economically viable. And the other is I think the Commission should be honored for their commitment to the hedging program. It's immature and it provides value to customers. Now, with that said, at the end of the day we are a price ticker. We can hedge to the limits of our hedge programs, but at the end of the day we are somewhat subject to the vagaries of the market.

We are very focused on fuel security. And as the coal supply chain devolves, that will be at least as much a priority for us as managing low cost, you know, the cost of the fuel in the short term. Maybe in the long term, that really will be the goal for us is to manage the long-term prices, and that, as we see more stress on the coal industry, that's going to be our focus.

Q So, you mentioned challenges that will rise this summer as we increase usage down here as it gets hotter and hotter and air conditioners are cranking, but you also mentioned shortage -- our storage constraints, but talk to me some about the winter. As we head into the winter, what's going to happen? I mean, in jurisdictions out other than -- jurisdictions across the country right now are expressing grave concerns about the electric system operation as we head into the winter. So tell me what you-all -- what you're seeing for our systems here in terms of fuel prices, your ability to procure fuel, your ability to ensure fuel security, and then your colleague's ability to operate the system efficiently.

A That's a great question and I think it touched on a lot of things beyond just price. We are focused on the impacts and have spent a fair amount of time looking into the impacts of crises or like what happened in Texas. So, there's a physical component to this, right.

So, we manage that with our physical and our financial hedging program. We are very aware of the burns in the winter and we prepare, and that's really a big focus for us. It's at the wintertime is where it becomes more difficult to secure additional natural gas. So, as part of our plan for that season, we put together a program using our Stochastic modeling that not only gives us what we expect the burn to be but also where we -- where the burn could come if we have an exceptional event.

Q Okay. Has -- you touch on this some in your testimony, but I want to follow up with you today. Has the Company or have the Company's -- or has the Company adapted its natural gas forecast and projections at all in light of the volatility we're experiencing right now and are likely going to continue to experience?

A Yes, Chair Mitchell. Absolutely. I probably should have spent more time on that, that Stochastic modeling. The purpose of that is to really try and encompass some of the volatility into the fuel forecast and the procurement strategy. Over the last two years or so we've been developing out that capability. We use it now for fuel procurement and for planning. We have not used it in rates yet, just because it's the impact of setting that fuel rate is significant, and we really just want to be thoughtful and make sure that we have -- we -- that if we switch from a deterministic point in time, which we use now, which obviously the flaws of which can be, things change from today to tomorrow. We haven't quite worked out exactly how we integrate the power of stochastics into that fuel forecast in terms of rates, but that's something we'll be working on shortly here with staff.

Q So, and your testimony touches on, and I mentioned this a minute ago, the projected increase in natural gas burn. Talk a little bit about how much what has been a -- what you-all experienced during the test period was influenced by Covid and potential rebound from Covid. Are we seeing -- are we sort of recovering from situations that occurred during Covid or are we going to see that in the next

fuel proceeding?
A So to move back to the forward curve --
Q And I recognize that's not a very clear question.
A Oh no, I think I -- well, I'll try and then if I need to get it --
Q Okay.
A So, there definitely, clearly have been impacts to both gas, the gas market on the production side and the coal market as well. Coal exacerbated by global events. From a production perspective, natural gas production has not returned to the point where it was pre-pandemic.
Q And what about usage on the Company's system? That's really what I'm focused on.
A So usage on the Company's system, that's a function of economics and availability. So that -- and that's a little bit lost in this testimony. And the timing of the first surge in energy prices came in the gas market as we recovered from the pandemic, and then that manifest itself into a run on coal. And so as you have different relationships between gas

and coal, that usage will change, and I think that's reflected in the forward position and the forward curve. Again, that's the best we see now. I think there is some risk that these prices stay higher and we don't see the - technical term is "backwardation" of the forward curve showing -- gas curve showing lower prices than the current spot. There is limited to no ability, no, what we call elasticity of supply in the coal market. There is no more coal to be bought. So that's going to naturally impact the economics of what was. So, did that --

A (Mr. Sykes) I'll add as well that the Company saw an increase of a little over 4 percent in this test period from the prior year, if that helps Duke Energy Carolinas North Carolina Retail jurisdiction at a 4 percent increase in sales.

A (Mr. Verderame) I will say we see some balancing in the commodity markets going forward. That's why we see -- you'll see less coal burn going forward. The forward market indicates the gas prices will be lower. Gas will be more economic. You see that most dramatically at the dual fuel units. That's where the switch mostly occurs.

Q Okay. Mr. Verderame, a couple of questions for you about the hedging, the Company's hedging practices and program. So, in recent years, the Company has extended its hedge horizons from 36 months to 60 months and from, I think, 25 months to 60 months in another instance. Help us understand the benefit -- help us understand the decision to extend the hedge horizon?

A Sure, Chair Mitchell. So, that first move to extend from 36 months to 60 months was really borne out of what we saw as a no-regrets move to -- in response to a really extended period of low gas prices and a forward curve that was very flat that showed there was not a lot of premium to the forward market, and customers almost had a, again, no-regrets opportunity to start layering some hedges out, further out to curve. So, as -- and then -- so that was that decision.

And then further to that, when,

as we started to see a growth in gas and the expectation would be more gas burned that, that it made sense to raise some of those percentages up just a little bit as well. It's still a very programmatic or fairly programmatic type of a program, but it allows -- those longer terms allow us to layer in hedges through time.

Q Okay. It's my understanding that Piedmont Natural Gas, obviously DEC's affiliate, hedges out 12 months. Is that -- are you aware of Piedmont's practices?

A I'm sorry, I'm not.

Q If that is the case and you were to accept that subject to check, any reason why -- can you think of any reason why Piedmont would hedge out only 12 months?

A I'm sorry, I can't.

Q A couple of questions from our -- from the staff of the Commission. On page 5 of your direct testimony, you state that the average price of the gas purchased for the test period was $4.22. Did I get that right? Is that right?

A That sounds right, yes.
Q I'm looking at page 5 of your direct. Did you prepare an exhibit that shows how you-all calculated the average price?
A Yes, there is -- I don't know if there is an exhibit for it. It might have been in a data request.
Q Okay. And just as a follow-up there, is there an exhibit in your testimony, in any of your testimonies filed that breaks down the components of the cost of gas?
A No, Chair. No.

CHAIR MITCHELL: I'd ask that you-all file as a late-filed exhibit such an exhibit to show how the average price was calculated and that average price is $4.22 which appears on page 5 of his direct testimony. And then, if you can in that exhibit or alongside that exhibit, break down the components of the cost of gas for us.

MR. KAYLOR: We can do that.

CHAIR MITCHELL: Gas, transportation, demand, storage, et cetera.

THE WITNESS: (Mr. Verderame) And hedges are in that price as well.

CHAIR MITCHELL: Okay.

THE WITNESS: (Mr. Verderame) It's an all-in cost. Sure, we can provide it.

CHAIR MITCHELL: Perfect. Thank you.

BY CHAIR MITCHELL:

Q You've talked some about the benefits to the customers in recent months of the hedging program, and I think you indicated approximately $114 million for this, for purposes of this proceeding; is that right?

A (Mr. Verderame) That's correct.

Q Okay. Help us understand how that -- those -- that $114 million benefit to customers splits between financial and physical hedges. Do you know that information?

A I would say those are all financial gains.

Q All financial? And so is there a way to monetize or quantify the benefits of physical hedges? Benefit or cost to customers.

A I'm not exactly sure. I think we probably can break that down. We can certainly look into it.

Q And just for purposes -- for my edification, talk some about a physical hedge. What are the types of physical hedges in which the Company engages?

A Yeah. So those are all part of how we, I'll say, set up the season or the system on a daily or even on a seasonal basis. So, we stack up physical purchases, delivered supply purchases, and then on top of that there are other optional.

I mention in my testimony optional instruments where we can define a fixed price of gas at some point in time. Some of them are monthly as we head into the month while others are predetermined. So, that would be more of the physical. We'd have to go back and look at when we struck on the physical options, you know, how they realize against the spot price.

Q Okay. And are those -- are the physical hedges, are those transactions that occur with Transco pursuant to the terms of your supply agreements with Transco, are those done on sort of the open market?

A No, those are done on the open market. We don't buy supply from Transco; they're only the transportation provider.

Q Okay, got it. And at this point in time, am I correct that the Company is not filing a monthly hedging report with the Commission?

A No, we do not. That's correct, we do not.

Q Okay.

A We do file it quarterly.

A (Mr. Sykes) Yeah, I believe we file some periodic report with Public Staff on a monthly or quarterly basis detailing several months worth of the hedging gains or losses.

Q Okay.

CHAIR MITCHELL: I will pause here to see if there are any other questions from Commissioners?

(No response)

Questions on Commission's questions?

MR. CREECH: Thank you, Chair Mitchell. Zeke Creech, again, with the Public Staff.

EXAMINATION BY MR. CREECH:

Q Witness Verderame, if you can -- obviously a lot of extensive questions just then. One I wanted to ask you about related to what y'all see for this year. And you indicate in the comments that you spoke a little while ago that based on January through April 2022 fuel reports we're seeing an under-recovery of $182 million already. And then you say based upon -- based on the latest forecast that we have, we expect to see approximately $228 million in total calendar 2022 under-recoveries. And so you may have touched on this, but if you can just explain why that is. Obviously, we're all very interested in pricing, hedging. Go ahead.

A So, I'll do the fundamental part and Witness Sykes can back me up on the actual numbers. You picked an interesting day for a hearing. Yesterday, the balance of the year natural gas price traded over $9.00 for the first time. So we see -- I'll just -- for the last five years have averaged below $3.00. The next five years averaged probably $5.50, but clearly in this next year or two, there is going to be volatility and high prices. So we expect the balance of 2022 natural gas to at this point trade above $9.00 per dekatherm, and 2023 currently trading about $6.00.

So you can see there is kind of of

a cliff until we get to some normalcy out in '24, '25, and '26 where we're getting closer to, you know -- closer to historical prices, around $4.00 or $4.50. So, not a return to $3.00 immediately here in the near future or on the coal side as well. Coal remained fairly elevated. It's extremely scarce right now. So we've come to the point where we are competing for a -- the marginal ton of coal with Europe and China, and so that will continue to be a struggle until that resolves itself.

Mostly in terms of what hits rates, gas, it's immediately because we don't have any storage. While coal, while these high prices set the dispatch price, the actual price that customers pay for the coal is not until it's actually burned. So you see a kind of a discrepancy, a little bit of a discrepancy.

A (Mr. Sykes) Yeah. And I would just add to that. This is based off a March forecast, so to the extent commodity, underlying commodity prices change, we could expect to see a different outcome in the total under-recovery for the balance of the year. I would also add that new rates, if approved by the Commission, the proposed rates that we have in front of you today go in effect September 1st. So, there's not a lot of time in the balance of '22 to make up for significant underlying commodity prices.

MR. CREECH: Thank you.

MS. CRESS: No questions.

MR. SCHAUER: Chair Mitchell, a few questions, please.

CHAIR MITCHELL: Go ahead.

MR. SCHAUER: Craig Schauer, CUCA.

EXAMINATION BY MR. SCHAUER:

Q Mr. Verderame, if I recall your testimony just recently, you said you would expect prices to potentially return to the $4.00 range somewhere in the time period of 2024 to '26. Earlier, you gave us a very detailed list of the drivers of the cost of natural gas, the price of natural gas, how do you -- what drivers do you anticipate shifting that will allow the price to finally subside back to $4.00?

A So, I think the primary one is going to be a return to some production. Again, if producers see some price sustainability outcome, that will incent some -- it should incent some production, and that would balance out the market. Because when there's -- again, there's always some impact from the demand side, as well, if there's a potential economic disruption as well, it could balance that out.

Q So just to recap, it sounds like the primary driver would be a return to production? Okay.

A I believe so, yeah.

MR. SCHAUER: Thank you. No further questions.

MS. JONES: No questions.

MR. KAYLOR: No questions on redirect.

CHAIR MITCHELL: Gentlemen, I actually have one more question for you, so we'll have to go through this again. Sorry, guys.

FURTHER EXAMINATION BY CHAIR MITCHELL:

Q The extent of the increase that the Company is asking the Commission to approve in this case, just considering the average residential user, is just under 10 percent, is that right, given the updated numbers?

A (Mr. Sykes) That's correct.

Q Do you-all -- are you-all aware of the extent of the increase that the Commission approved in the Company's last general rate case?

A I don't have the numbers in front of me. It was approximately a 1.34 percent decrease I believe.

Q Well, it was impacted by the EDIT Riders. As you're aware the Company is returning EDIT through riders that phase out over time, so that has rounded the edges out for customers who are experiencing those rate increases.

But I'm looking at the customer notice right now and when that -- upon the expiration of EDIT Rider 4, which happens five years out from the Commission's Order in that rate case that was tried in Sub 1214, the increase to customers, the residential customer, would be $8.45 per month. So in this proceeding alone, customers are going to experience $10.00 a month for the next year. So, I just -- does that sound right to you-all? Is that squaring with what you're telling us today, is that customers are going to have a pretty significant shock once these rates go into effect?

A Yes, that is correct, based off of everything that we're seeing today.
Q Okay. And, Mr. Verderame, I've asked you this already, but I understand your testimony today to be that you-all are going to do everything you can to insulate customers from the volatility that is happening in the markets right now?
A (Mr. Verderame) Yes, Chair. Again, we're somewhat subject to the vagaries in the market, but outside of that we're also very focused on other ways that we can reduce customers' costs.
Q And manage this risk. And I want you to -- I interrupted you so I'll let you proceed, but I want to hear that you-all are actively engaged in managing this risk?
A It is very front of mind for us.

CHAIR MITCHELL: All right. Any questions on my question? Let's see, over on this side? Mr. Creech?

MR. CREECH: No.

CHAIR MITCHELL: Ms. Thompson?

MS. THOMPSON: Yes, please, one question on your last question. Sorry about that.

EXAMINATION BY MS. THOMPSON:

Q Mr. Verderame, Gudrun Thompson representing the Southern -- the Sierra Club. In response to Chair Mitchell's last question about providing insurance that the Company is going to do all it can to mitigate the risk of fuel price volatility to its customers, understand that there -- that the Company doesn't control the gas markets, correct?

A Correct.

Q And I think earlier or you had alluded to being able to control the operations of your system. Is it correct that the Company can control the way it operates its system?

A Yes.

Q And isn't it also true that the Company can control what resources it seeks to add to its system and the resources for which it seeks Commission approval?

A Subject to Commission approval, but yeah.

Q Correct. And isn't it also true that -- or are you aware that the proposed Carbon Plan recently filed by the Company and Duke Energy Progress includes over two gigawatts of new gas combined cycle capacity in each of the four proposed portfolios?

A I am.

Q Thank you.

MS. THOMPSON: That's all I have. Thank you, Chair Mitchell.

CHAIR MITCHELL: Mr. Kaylor?

MR. KAYLOR: No questions.

CHAIR MITCHELL: With that, gentlemen, you all may step down. Mr. Kaylor, I'll take a motion.

MR. KAYLOR: Yes. I would move that the exhibits which has previously been marked for the record be accepted into evidence.

CHAIR MITCHELL: Hearing no objection, we will allow -- we will accept the exhibits into evidence.

(WHEREUPON, Verderame Exhibits 1, 2 and Confidential Exhibit 3; Sykes Exhibits 1-6, Workpapers 1-13, Revised Exhibits 1-4, Exhibit 5, Exhibit 6 Revised Schedule 10, Revised Workpapers 7, 10, 12 and 13 are admitted into evidence.)

MR. KAYLOR: And I believe I also moved the Application already.

CHAIR MITCHELL: You did. We got the Application. Gentlemen, thank you for your testimony today. Y'all may step down.

MR. KAYLOR: And that concludes our case.

CHAIR MITCHELL: With that, I'm not hearing anything from counsel. Well, actually, Mr. Creech, go ahead.

MR. CREECH: If you would like for us to call Witnesses Lawrence and Metz, we can.

CHAIR MITCHELL: Let's do that. And let's also move Ms. Chiu's affidavit in.

MR. CREECH: Certainly. The Public Staff would ask that Witness Chiu's affidavit be entered into the record.

CHAIR MITCHELL: Hearing no objection, that motion will be allowed.

MR. CREECH: Thank you.

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

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1263

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

STATE OF NORTH CAROLINA

COUNTY OF WAKE

I, June Chiu, first being duly sworn, do depose and say:

I am a Financial Analyst III in the Accounting Division of the Public Staff - North Carolina Utilities Commission. A summary of my duties, 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, 2021.

In its application, filed with supporting testimony on March 1, 2022, 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	0.3785 cents per kWh
General Service/Lighting	0.4625 cents per kWh
Industrial	0.4128 cents per kWh

On May 9, 2022, DEC filed the Direct Testimony of David B. Johnson and the Supplemental Testimony of Bryan L. Sykes with Revised Sykes Exhibits and supporting workpapers. Witness Sykes' supplemental testimony and revised exhibits reflect the impact of four updates to numbers presented in witness Sykes' direct exhibits and workpapers. They are as follows:

(1) An update to the EMF increment to incorporate the fuel and fuel-related cost recovery balances for January 2022, pursuant to Commission Rule R8-55(d)(3). The reported 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;

(2) An update to the production plant allocator used to allocate renewable and purchased power capacity costs to the North Carolina Retail jurisdiction to reflect the production plant allocation factor in the 2021 cost of service study, which provides a decrease in the under-recovery of the fuel costs. The Company had previously utilized the 2020 production plant allocation factor since the 2021 study was not complete;

(3) An update to revise the coincidental peak data reported on Exhibit 4, which was not available at the time of the Company's initial filing in this docket. The coincidental peak data is informational and has no impact on proposed rates; and

(4) A revision to the retail customer growth adjustment and the wholesale weather adjustment. The retail customer growth adjustment reflects the actual number of customers more accurately within the test period. This adjustment increases the EMF rate as proposed on the Sykes Revised Exhibit 3, which uses normalized test period sales. However, the wholesale weather adjustment does not impact proposed rates.

Revised Sykes Exhibit 1 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	0.4863 cents per kWh
General Service/Lighting	0.6254 cents per kWh
Industrial	0.5726 cents per kWh

In witness Sykes' Revised Exhibits, DEC's proposed revised under-recovery of fuel for each of the North Carolina retail customer classes is as follows:

Residential	$111,487,845
General Service/Lighting	$145,085,337
Industrial	$70,401,036

The revised riders were calculated by dividing the fuel cost under-recoveries by DEC's normalized test year N.C. retail sales of 22,926,377 megawatt-hours (MWh) for the residential class, 23,198,571 MWh for the general service/lighting class, and 12,293,985 MWh for the industrial class.

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

As a result of the Public Staff's investigation, I am recommending that DEC's EMF riders for each customer class be based on net fuel and fuel-related cost under-recoveries of $111,487,845 for the residential class, $145,085,337 for the general service/lighting class, and $70,401,036 for the industrial class, and normalized North Carolina retail sales of 22,926,377 MWh for the residential class, 23,198,571 MWh for the general service/lighting class, and 12,293,985

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	0.4863 cents per kWh
General Service/Lighting	0.6254 cents per kWh
Industrial	0.5726 cents per kWh

I have provided these amounts to Public Staff witnesses Lawrence and Metz for incorporation into their recommended final fuel factor. The Public Staff also reserves its rights to review and audit the January 2022 fuel and fuel-related costs.

This completes my affidavit.

June Chiu

June Chiu

Sworn to and subscribed before me
this the 16 th day of May, 2022.

Jessica Heironimus

Notary Public

My Commission Expires: May 10, 2023

JESSICA HEIRONIMUS NOTARY PUBLIC WAKE COUNTY, N.C.

APPENDIX A

JUNE CHIU

Qualifications and Experience

I graduated from Drake University with a master's degree in Business Administration. Prior to joining the Public Staff, I worked in the state government and corporate areas. My duties varied from performing audit engagements to supervision of accounting and internal controls and preparing SEC filings.

I joined the Public Staff in October 2017. I am responsible for (1) examining and analyzing 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) preparing and presenting testimony, exhibits, and other documents for presentation to the Commission.

I have performed audits and/or presented testimony and exhibits before the Commission for water and telecommunication cases involving Ridgecrest, Water Resources, Aqua, Lake Junaluska, Carolina Water Service Inc. of NC, JAARS, etc. I have participated in electric cases such as the Dominion Energy North Carolina 2019 general rate case, Duke Energy Carolinas, LLC's 2019 general rate case, Dominion Energy North Carolina fuel cases since 2019, Duke Energy Progress, LLC's REPS proceedings since 2020, and Duke Energy Carolinas, LLC's Fuel case since 2021.

MR. CREECH: So, we're calling Witnesses Lawrence and Metz. And the parties to my knowledge, we filed -- did not have cross so, without objection, we'll have them appear as a panel.

MR. KAYLOR: No objection.

CHAIR MITCHELL: Okay. You may proceed.

MR. CREECH: Mr. Lawrence --

CHAIR MITCHELL: Let's get them sworn in.

As a panel,

EVAN D. LAWRENCE and DUSTIN R. METZ;

having been duly sworn,

testified as follows:

CHAIR MITCHELL: Mr. Creech?

MR. CREECH: We'll start with Mr. Lawrence.

DIRECT EXAMINATION BY MR. CREECH:

Q Mr. Lawrence, will you please state your name, business address and present position for the record?

A My name is Evan Lawrence. My business address is 430 North Salisbury Street, Raleigh, NC. And my current position is a Utilities Engineer with the Public Staff's Energy Division.

Q Mr. Metz, if you will do the same. Please state your name, business address and present position for the record?

A My name is Dustin Metz. Business address is 430 North Salisbury Street, Raleigh, North Carolina. I'm an Engineer with the Operations and Planning Division with the Public Staff.

Q And Mr. Lawrence, on May 17th, 2022, did you and Mr. Metz jointly prepare and cause to be filed in this docket joint testimony consisting of 16 pages inclusive of two appendices, attached to which there were three exhibits being Lawrence/Metz Exhibits 1 to 3?

A Yes.

Q Is that right, Mr. Metz?

A That is correct.

Q Mr. Lawrence, do you have any corrections to your testimony?

A Not at this time, no.

Q Mr. Metz?

A Not at this time.

Q Mr. Lawrence, if you were asked the same questions from your testimony today, would your answers be the same?

A Yes.

Q Mr. Metz?

A They would be the same.

MR. CREECH: Chair Mitchell, I move that the joint testimony consisting of 16 pages inclusive of their two appendices be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection to that motion, it will be allowed.

(WHEREUPON, Lawrence/Metz Exhibits 1, 2 and 3 are marked for identification as prefiled.)

(WHEREUPON, the prefiled joint testimony and Appendices A and B of EVAN D. LAWRENCE and DUSTIN R. METZ is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1263

In the Matter of		
Application of Duke Energy Carolinas, LLC, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	))))))	JOINT TESTIMONY OF EVAN D. LAWRENCE AND DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

Q. MR. LAWRENCE, PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Evan D. Lawrence. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer with the Operations and Planning Section in the Energy Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. My education and experience are summarized in Appendix A to this testimony.

Q. MR. METZ, PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

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

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer with the Operations and Planning Section in the Energy Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. My education and experience are summarized in Appendix B to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR JOINT TESTIMONY?

A. The purpose of our testimony is to present the results of the Public Staff's investigation and recommendations regarding the proposed fuel and fuel-related cost factors for the residential, general, service/lighting, and industrial customers of Duke Energy Carolinas, LLC (DEC or the Company), as set forth in the Company's application and testimony filed March 1, 2022, and additional direct testimony and supplemental testimony filed May 9, 2022. Additionally, our testimony: (1) highlights a concern relating to the Clemson Combined Heat and Power (CHP) steam sale contract, which has been raised in previous dockets; and (2) reports minor findings relating to the actual operations of and billing for the Clemson CHP in the test period.

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

A. For this proceeding, the test period is January 1, 2021, through December 31, 2021, and the billing period is September 1, 2022, through August 31, 2023.

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

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

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

A. For the test year, the Company achieved the nuclear capacity factor standard in Commission Rule R8-55(k) and appropriately calculated the proposed base system average fuel factor for the billing period. The Company's estimated proposed fuel and fuel-related cost factors in this proceeding are reasonable. We discuss factors that increased the price of fuels in the test year. During the test year, these factors resulted in a large under-collection of costs, and they continue to have significant impacts on commodity costs for present and future electric generation.

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

A. Yes. For the test year, the Company achieved the standards of Commission Rule R8-55(k) by achieving an actual system-wide nuclear capacity factor that exceeded the NERC (North American Electric Reliability Corporation) weighted average nuclear capacity factor. Additionally, the Company's two-year simple average of its system-wide nuclear capacity factor exceeded the NERC weighted average nuclear capacity factor.[1]

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

A. Yes. The projected fuel and reagent costs are reasonable and were calculated appropriately. The projected fuel and fuel-related costs are impacted by fluctuations in the costs of nuclear fuel, coal, and natural gas. DEC based its proposed fuel and fuel-related costs on a 93.94% system nuclear capacity factor, which the Company anticipates for the billing period.

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

[1] The Company's actual system nuclear capacity factor for the test period was 96.12%. In comparison, the most recent NERC five-year average weighted for the size and type of reactors in DEC's nuclear fleet was 92.10% during the test period.

A. Lawrence/Metz Exhibit 1 shows the proposed fuel and fuel-related cost factors. The Public Staff recommends approval of the fuel components and total fuel factors (excluding the regulatory fee), shown in Lawrence/Metz Exhibit 1, Table 1, effective for the twelve-month period beginning September 1, 2022.

Public Staff witness Chiu discusses the Public Staff's review of the test period Experience Modification Factor (EMF) and EMF interest in her affidavit, and her recommendations are incorporated in Lawrence/Metz Exhibit 1.

Q. YOU STATED PREVIOUSLY THAT YOU REVIEWED TEST YEAR POWER PLANT PERFORMANCE. DID ANY PARTICULAR OUTAGES OR EVENTS OCCUR THAT YOU WOULD LIKE TO BRING TO THE COMMISSION'S ATTENTION?

A. No. In previous orders,[2] the Commission instructed the Public Staff to continue to investigate and present its concerns to the Commission regarding test year outages. The Public Staff reviewed multiple outages that occurred during the test year, but this review did not raise any concerns that need to be presented to the Commission at this time.

Q. HOW WERE THE BILLING PERIOD COSTS PROJECTED?

---

[2] Docket No. E-22, Sub 546, Order Approving Fuel Charge Adjustment, Evidence and Conclusions for Findings of Fact Nos. 6-9, p. 19, January 25, 2018; and Docket No. E-7, Sub 1163, Order Approving Fuel Charge Adjustment, Evidence and Conclusions for Findings of Fact Nos. 4-6, p. 28, August 20, 2018.

A. As previously noted, the billing period for this case is September 1, 2022, through August 31, 2023. DEC developed the projections of fuel costs in December 2021 as part of preparing its application, testimony, and exhibits for initial filing in March 2022. In fuel application proceedings, DEC must make cost projections from 9 to 21 months in advance. Commodity costs of fuels, transportation costs of fuels, plant dispatch and availability, fuel availability, and many other factors must be considered to develop the estimated prospective billing factors. In past years, future fuel costs were less volatile, and generally only severe weather events or extended plant outages caused significant cost fluctuations in the annual fuel riders.

Q. DOES THE PUBLIC STAFF DISAGREE WITH THE COMPANY'S PROJECTED COSTS FOR THE BILLING PERIOD?

A. No. The Company has projected costs for the billing period utilizing the uniform bill adjustment method it has used in previous years. This method includes using a production cost model which uses inputs such as the forward market price of fuel commodities, the fuel transportation costs, and expected plant operations to develop a scenario that is "most likely" to occur. However, the Public Staff feels it is important to highlight some of the dynamics that expose ratepayers to the risks of volatile fuel prices. Overall, fuel prices have been particularly volatile over the last year. The Company has increased its reliance on natural gas over the past several years, exposing DEC to greater natural gas price volatility. Figure 1, below, shows the amount of natural gas burned by DEC (in million British thermal units (MMBTU)), compared to DEC expenditures on natural gas for the years 2016-2021, as well as the billing period projection for this proceeding. Lawrence/Metz Exhibit 2 includes Table 3 which shows the actual values in Figure 1.

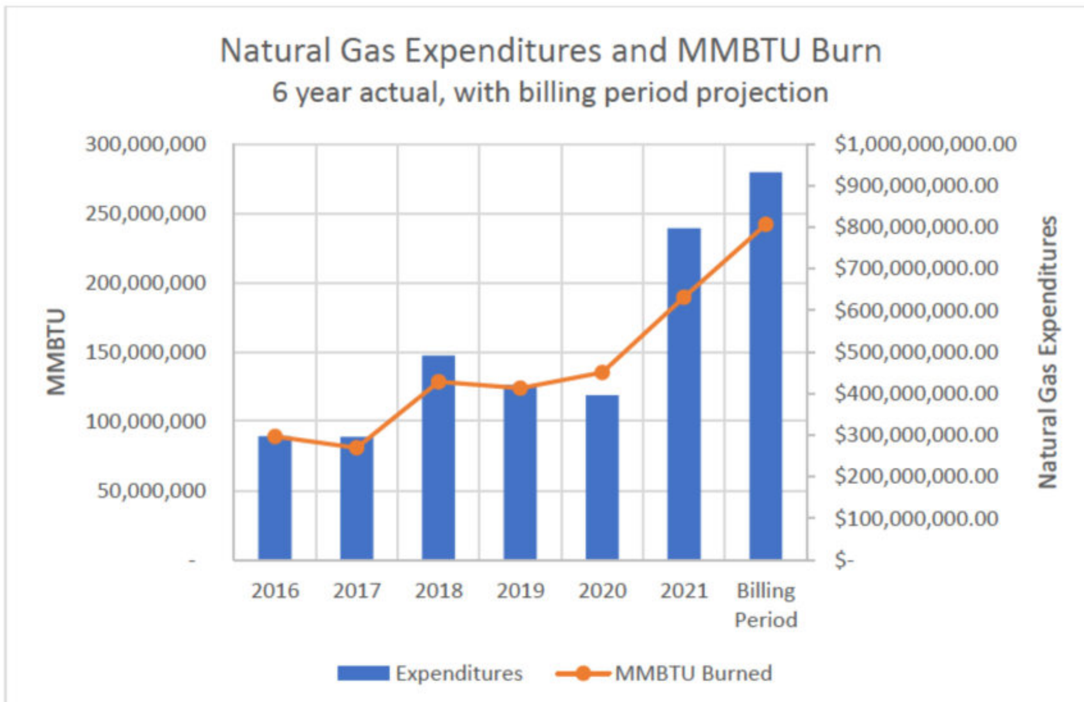

Figure 1: DEC natural gas commodity expenditures and MMBTU burned

Q. PLEASE DISCUSS WHAT CONDITIONS HAVE CHANGED SINCE DEC MADE ITS BILLING PERIOD PROJECTION.

A. The most substantial impact to the annual fuel rider is the increased price of natural gas for which DEC is seeking cost recovery in this case. DEC witness Vederame's direct testimony, page 9, line 20, indicates that the Henry Hub forward price for the billing period was \$3.60/MMBTU. Currently, the Henry Hub forward price for the billing period is up to \$6.58/MMBTU as of May 16, 2022.[3] While the Public Staff does not expect natural gas prices to fall in line with witness Vederame's estimate during the billing period, the Company's hedging program is intended to help mitigate the disparity between projected and actual costs.

On November 5, 2021, in Docket No. E-22, Sub 605, Public Staff witness Lawrence filed testimony that discussed reasons why Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC) had appropriately requested an increase to its fuel rates. At that time, the Public Staff and DENC recognized that natural gas prices were increasing and would continue to increase from the levels realized during much of 2020 and part of 2021. In his testimony, Witness Lawrence stated the following:

> The Henry Hub natural gas price projections from the Energy Information Administration (EIA) Short-Term Energy Outlook, published October 13, 2021, project gas prices increasing to a monthly average peak of \$5.90/MMBTU in January 2022 with a gradual decline to an average of \$4.01/MMBTU for all of 2022. Both Duke Energy's and Dominion's confidential fuel forecasts trend to the EIA's short-term increase in gas pricing with a gradual decline through 2022. It is noteworthy that the current gas price forecasts are only estimates, and market conditions along with colder

[3] Source: https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.quotes.html

weather or an active 2022 hurricane season in the Gulf of Mexico may impact current projections.

Global events and market conditions, such as the ongoing war in Ukraine[4] and inflationary pressures,[5] have contributed to the current higher fuel and other commodity prices. In fact, DEC witness Vederame indicates that the Company expects the price of delivered coal to increase to $91.89 per ton for the billing period, compared to $78.22 per ton for the test period.[6]

These impacts should not be as substantial on the near-term price of nuclear fuel due to the Company's fuel procurement strategy, discussed in DEC witness Houston's direct testimony. He states that the average nuclear fuel expense is expected to increase from 0.5726 cents per kilowatt-hour (kWh) in the test period to 0.5773 cents per kWh in the billing period.

Q. WHAT IS THE CLEMSON CHP FACILITY?

A. The Clemson CHP is a 16 megawatt natural gas-fired generation station owned by DEC, located in Pickens County, South Carolina, near Clemson University. The energy in the exhaust gas produced during generation is converted to steam as a byproduct. The steam byproduct is processed and sold by DEC to Clemson University

[4] https://www.cnbc.com/2022/04/18/natural-gas-surges-to-highest-level-since-2008-as-russias-war-upends-energy-markets.html

[5] https://abcnews.go.com/US/wireStory/producer-prices-surge-112-march-higher-energy-costs-84056058

[6] Direct Testimony of DEC witness John A. Vederame, page 8 line 24 – page 9 line 1.

pursuant to a steam sale contract (SSC) that is provided as Lawrence/Metz Exhibit 3.

Q. WHAT IS YOUR CONCERN RELATED TO THE CLEMSON CHP AND FUEL RATES?

A. The Clemson CHP had multiple unit outages, impacting the availability and capacity factor. The outages and availability, to date, are sub-optimal per the designed capacity factor. The operating ability of the CHP has improved but is currently not close to achieving the designed availability factors. Sub-optimal performance and/or cycling of the Clemson CHP may result in higher and less efficient heat rates, resulting in more natural gas consumption for an equivalent electricity and steam output than could occur at a higher capacity factor. This results in higher fuel costs that the Company would likely seek to pass on to ratepayers.

The Clemson CHP was placed in service on or around December of 2019. Clemson University did not complete construction of its section of the steam system until December of 2021. The Clemson CHP was designed to achieve a 90-95% capacity factor, but because of the delay in the construction of the steam system, it was dispatched much like a peaking unit. The realized fuel costs (cents/kWh) of DEC's peaking assets, filed as part of its monthly fuel reports (see

Schedule 5) per Commission Rule R8-52, show the effect of economic dispatch of system resources on system fuel costs.[7]

Q. ARE YOU RECOMMENDING AN ADJUSTMENT IN THIS CASE?

A. No. The SSC structure and Clemson CHP generation plant outages occurring in 2021 did not result in a significant monetary concern in the 2021 test year, but natural gas price volatility has exacerbated our concerns regarding the potential negative outcomes discussed in previous testimonies.[8] Primarily, the SSC does not allow a true-up of the natural gas price and other provisions, so it is difficult for DEC to match annual steam sales revenue to natural gas prices when prices are greatly increasing. These factors may be disadvantageous to North Carolina retail ratepayers.

As part of its investigation in this docket, the Public Staff has discussed its concerns regarding the Clemson CHP with the Company. The Company has agreed to have further discussions with the Public Staff to attempt to resolve these concerns.

---

[7] Multiple factors are considered for system dispatch, and it is possible that given grid constraints or other factors, units may have to be run out of uneconomic order in some cases.

[8] Testimony of Dustin R. Metz filed May 18, 2020, in Docket No. E-7, Sub 1228, and Supplemental Testimony of Dustin R. Metz filed March 25, 2020, in Docket No. E-7, Sub 1219 pp. 5-14, supporting Exhibits, and related settlement.

Q. FOR THE TEST YEAR, DID THE PUBLIC STAFF AUDIT CLEMSON CHP INVOICES?

A. Yes, the Public Staff audited the Clemson CHP test year monthly invoices and found a minor issue with the test year revenues and billing data; DEC has been notified about this finding. The Public Staff is concerned about the invoices and in particular the SSC Exhibit C Payment Calculation equation and explanation that centers on the New York Mercantile Exchange (NYMEX) Henry Hub (HH) price. A minor time series misalignment exists between DEC's test year (calendar year) and the SSC June to July NYMEX HH price. DEC used the same NYMEX HH price throughout the entire calendar year, instead of using two discretely different natural gas prices. Based on initial analysis and the time misalignment of six months, the adjustment would likely be immaterial and not change the fuel rate in this case.

However, the Company and the Public Staff have agreed that this limited issue of steam sale revenue should be trued-up and reflected in next year's annual fuel rider (2023) and adjusted back to the initiation of the SSC.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, this concludes our testimony.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

EVAN D. LAWRENCE

I graduated from East Carolina University in Greenville, North Carolina in May 2016, earning a Bachelor of Science degree in Engineering with a concentration in Electrical Engineering. I started my current position with the Public Staff in September 2016. Since that time, my duties and responsibilities have focused on reviewing renewable energy projects, rate design, renewable energy portfolio standards (REPS) compliance, and annual fuel rider proceedings. I have filed affidavits in Dominion Energy North Carolina's 2017 and 2018 REPS cost recovery proceeding, testimony in DENC's 2021 fuel cost recovery proceeding, testimony in DEP's 2019 REPS cost recovery proceeding, an affidavit in DEC's 2019 REPS cost recovery proceeding, testimony in New River Light and Power's most recent rate case proceeding, testimony in Western Carolina University's most recent rate case proceeding, and testimony in multiple dockets for requests for CPCNs.

Appendix B

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I completed engineering graduate course work in 2019 and 2020 from North Carolina State University.

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

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

MR. CREECH: And Chair Mitchell, the witnesses are available for Commission's questions.

CHAIR MITCHELL: Good morning, gentlemen. Let me check in with colleagues to see if anyone has questions for you-all. I've got a few for you.

EXAMINATION BY CHAIR MITCHELL:

Q Supplemental updated -- supplemental testimony and updated numbers, have you-all, Public Staff, had a chance to review that additional information?

A (Mr. Lawrence) We have reviewed the numbers and how they flow through. We haven't reviewed yet for appropriateness and prudence, that will be done in the next fuel case.

Q Any objections or concerns with what has been filed as supplemental information in this docket?

A (Mr. Metz) No.

Q Any -- you heard my questions for Company witnesses about volatility and insulating customers during this period of time when we anticipate that there will be volatility in the natural gas market, and the continued closure of the coal facilities, and the reality of the coal market right now. Is there anything else that you-all believe the Company could be or should be doing to insulate customers from this risk, these risks?

A (Mr. Metz) So, during the conversation I believe there was a few components talked about. There is the fuel cost risk but there's also the, what we call a fuel security risk.

So, not to ask the Chair a question, are you highlighting the fuel security standpoint or more of the cost element?

Q All of the above. I mean, recognizing that certain external forces are beyond the Company's control. What I'm focused on is what can the Company do right now to manage the volatility that -- you know, to manage this risk that the volatility imposes on customers. And if the answer is nothing, nothing more than what they've testified, that's fine. I just want to make sure there's nothing else that you-all can think of or have discussed that we should be aware of.

A There is no additional items that we have discussed other than what's been presented today.

Q Okay. In your testimony, you note the disparity between the gas price the Company was using and the gas price -- and I think your testimony identified gas price in March. Why not -- did you -- what discussions did the Public Staff have about utilizing, sort of, more recent forecasts than that which they utilized?

A So the Duke witnesses stated earlier, sort of, the overall timeline of what it takes to get a fuel filing ready. In my words, pencils down, or about in December, and it takes a few weeks to complete everything to make the filing. We were having internal conversations. And when Duke made the filing, we also reached out and had multiple meetings with Duke saying okay these are your projections. And we were both very cognizant and sensitive of the actual rate increases in this case, and what were the projections, and just using round numbers here. I believe when we started the conversation, potentially in March, looking at the NYMEX natural gas price of around the $6.00 to $7.00 range, with looking at those forward curves, there was a potential that they could go up and there was a potential that they could go down, and I believe Mr. Lawrence covered this in his testimony. Similar to the conversations we had in the Dominion fuel filing at the end of last year, in internal conversations on the DEP filing when we started noticing this trend. So, when we looked in March there was no immediate expectation that the gas prices would be approximately $9.50 as of yesterday. So, as more time passes, one has more clarity into what the actual exposed volatility is.

A (Mr. Lawrence) And I will add that we had similar discussions in the fall with Dominion Energy when they had filed for their fuel case, and there were concerns at that time about updating essentially the filing, the coal filing, later in the discovery period, test period, and then at what point is too late.

Normally, we don't see these types of price changes between the time the case is filed and shortly after, even as we saw this time until the hearing. This is a historically-unusual situation. I don't know how unusual it's going to be moving forward. And that is something with the update, and the update is something that we have discussed in this and Dominion's fuel case in 2021, and those discussions are going to be ongoing to ensure that we get something that's fair for everybody, appropriate rates, and for customers.

A (Mr. Metz) Just again, to reiterate an item prevalent to this case was the overall magnitude in waiting the potential outcomes of saying here is the potential increase. And if you were to update to the most current projection prices, the cost impact to ratepayers would have been well north of 10 percent.

Q Bleak outlook. Any concerns with the Company's hedging practices? Anything to -- anything in response to the testimony Mr. Verderame gave or anything that the Commission should be aware of related to the Company's hedging programs?

A No additional information to add on to the Duke witness.

A (Mr. Lawrence) I have nothing.

CHAIR MITCHELL: Okay. Commissioners? Anybody else? Questions on Commission's questions?

MR. KAYLOR: No questions.

CHAIR MITCHELL: Anybody on this side?

(No response)

With that, gentlemen, y'all may step down. Anything else? Any other motions from the Public Staff?

MR. CREECH: Chair Mitchell, we would want to move Lawrence/Metz Exhibits 1 to 3 into evidence, that they be numbered for identification as premarked in the filing.

CHAIR MITCHELL: The motion is allowed.

(WHEREUPON, Lawrence/Metz Exhibits 1, 2 and 3 are admitted into evidence.)

CHAIR MITCHELL: Mr. Kaylor, my recollection is you've got confidential testimony in this proceeding, confidential information in one of the exhibits, is that --

MR. KAYLOR: That's correct.

CHAIR MITCHELL: Okay. I'd just ask that

you-all make sure that that confidential information is so indicated in the transcript.

MR. KAYLOR: Yes.

CHAIR MITCHELL: Ms. Thompson?

MS. THOMPSON: Yes. Chair Mitchell, just before you adjourn, just out of an abundance of caution, if I may make a motion with regard to our witness' --

CHAIR MITCHELL: Please do.

MS. THOMPSON: I would move that Gregory M. Lander's testimony consisting of some 22 pages, which was filed in both confidential and public versions, be copied into the record as though given orally from the stand, and that the confidential version remain under seal, and that Mr. Lander's two exhibits also be admitted into evidence.

CHAIR MITCHELL: Hearing no objection, Ms. Thompson, the motion is allowed.

(WHEREUPON, Exhibits GML-1 and GML-2 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of GREGORY

M. LANDER is copied into the record as if given orally from the stand.)

PUBLIC VERSION
Confidential Information Redacted

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
Application of Duke Energy Carolinas,	)	**DOCKET NO. E-7, SUB 1263**
LLC Pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55	)	
Relating to Fuel and Fuel-Related	)	
Charge Adjustments for Electric Utilities	)	

DIRECT TESTIMONY AND EXHIBITS OF
GREGORY M. LANDER

ON BEHALF OF
THE SIERRA CLUB

May 17, 2022

I. Introduction and Qualifications

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

A. My name is Gregory M. Lander. I am President of Skipping Stone, LLC ("Skipping Stone"). As President, I lead Skipping Stone's Energy Logistics and Energy Contracting practice line. My business address is 83 Pine Street, Suite 101, Peabody, MA 01960.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I graduated from Hampshire College in Amherst, Massachusetts in 1977 with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in Citizens Energy's natural gas business in 1983. Between 1983 and 1989, I served as Manager, Vice President, President, and Chairman of Citizens Gas Supply Corporation, a subsidiary of Citizens Energy. I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, FERC Section 4 pipeline general rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, producers and industrial end-user matters, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded Trans Capacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). Between 1994 and 2002, I served as a Chairman of the Business Practices Subcommittee, along with serving on the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces.

I am currently a NAESB Board Member and have served continuously in that capacity since 1997. Skipping Stone acquired Trans Capacity in 1999, and since that time, I have led Skipping Stone's Energy Logistics and Energy Contracting practices, where I have specialized in interstate pipeline capacity issues, information, research, pricing, acquisition due diligence, and planning.

From 1984 to the present, I have maintained a deep familiarity with a wide range of pipeline transportation and contracting issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and determining what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process(es). I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on over fifty pipeline and storage mergers and acquisitions transactions, as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

Q. HAVE YOU FILED TESTIMONY IN REGULATORY PROCEEDINGS BEFORE?

A. Last year, I pre-filed direct testimony with the North Carolina Utilities Commission ("Commission") in Docket No. G-5, Sub 635, on behalf of Haw River Assembly and in connection with Public Service Company of North Carolina, Inc.'s application filed pursuant to N.C. Gen. Stat. § 62-133.4 and Commission Rule R1-17(k)(6) for review of its gas costs. In addition, I have filed testimony and/or reports in several proceedings before FERC and other state public utility commissions, including in Maine, Massachusetts, New York, New Jersey, Missouri, California, the District of Columbia, Virginia, and South Carolina. Please refer to Exhibit GML-1 for my current curriculum vitae and Exhibit GML-2 for a full list of cases in which I have filed testimony.

II. Testimony Overview

Q. WHAT ISSUES DO YOU ADDRESS IN YOUR TESTIMONY?

A. I will address the degree to which Duke Energy Carolinas' reliance on fossil-fueled generation, specifically gas-fired generation, exposes ratepayers to significant fuel price risk, and I will provide recommendations to address and potentially mitigate ratepayers' exposure to this cost risk. First, I will briefly summarize the fossil fuel and fuel related costs Duke Energy Carolinas, LLC ("DEC" or "the Company") seeks to recover in this proceeding, with a focus on gas[1] costs. As is evident from DEC's requested fuel charge adjustment, recent high and increasingly volatile gas prices are heavily impacting DEC ratepayers' electricity costs. I will then discuss some of the strategies utilities adopt to mitigate their customers' exposure to fossil fuel price volatility. I will also highlight some of the measures DEC employed to mitigate its customers' exposure and identify the limits of such strategies, even if they are helpful in the short-term. I will then highlight how fuel-free renewable energy can help DEC mitigate its customers' exposure to fossil fuel price volatility. Lastly, I will propose certain planning and forecasting recommendations that will help DEC anticipate and respond to future gas price volatility.

[1] As used in this testimony, the term "gas" refers to methane gas produced from wells and transported by pipeline(s) to consumption sites.

PUBLIC VERSION
Confidential Information Redacted

III. Reliance on Fossil Fuels Exposes Ratepayers to Risk

Q. PLEASE BRIEFLY DESCRIBE THE COSTS THAT DEC SEEKS TO RECOVER IN THIS PROCEEDING.

A. The Company is seeking to collect unrecovered fuel and fuel related costs that were incurred during the 2021 calendar year ("the Test Period"), as well as estimated costs for the September 1, 2022 through August 31, 2023 billing period ("the Billing Period"). With respect to the Test Period, the Company initially sought $245 million in under-recovery. As detailed in the Company's supplemental testimony, that under-recovery grew by another $81.99 million from just the under-recovery in January 2022, with the Company's total under-recovery amounting to $326.97 million. One significant factor was the increase in gas prices last year when compared to the Company's approved 2021 price projections. From my review and analysis of the Company's discovery responses, the Company's total gas costs in 2021 were $[redacted][2] or about $[redacted] million per month on average. Accordingly, the January 2022 under-recovery was more than half the 2021 average monthly amount spent on gas – representing over a 50% increase in cost in one month.

---

[2] These total gas costs were listed in the Company's response to SC-DEC 1-1. These purchases may also include purchases made by Company and re-sold (i.e., not burned). My analysis of SC-DEC 1-1 shows total purchases of [redacted] million dth for the Test Period versus a Company reported "Burn" of 189.6 Million dth. However, for the purposes of this testimony, inclusion of such purchase volumes and associated prices does not change any observations or conclusions herein.

The total fossil fuel costs used to calculate the Company's proposed fuel factor are $1.234 billion. The Company's system fuel expense for fuel factor is $1.671 billion, with fossil fuels accounting for 73.89% of the system expense.

The Company reports a gas burn of 189.6 million dth for the Test Period. With respect to the Billing Period, the Company projects that its gas burn will be 242 million MMBtu, which is a projected increase of 27% over the Company's Test Period burn. With regard to the Billing Period burn, it is not clear why DEC witness John A. Verderame states that "[t]he Company now expects projected natural gas burn volumes to be reduced based on delays in anticipated lower cost supply coming into the portfolio."[3] After all, a projected 27% increase is an increase, not a reduction.

Q. PLEASE SUMMARIZE THE IMPACT TO DEC CUSTOMERS' BILLS IF THE COMMISSION APPROVES DEC'S FUEL CHARGE ADJUSTMENT APPLICATION.

A. DEC's proposed fuel charge adjustment would result in a $9.85 increase to the monthly bill of a typical residential customer that uses 1,000 kilowatt hours of electricity each month. However, looking at just the increase in the fuel factor for residential customers, the increase from 1.5014 cents per kWh to 1.9315 in the initial filing represents a 28.6% increase in that component of residential bill charges. This is a significant increase at a time when DEC's customers

[3] Direct Testimony of John A. Verderame, page 9, lines 22-23.

are already saddled with higher grocery bills, gasoline prices, and consumer good costs due to inflation.

Q. WHAT FINANCIAL RISKS DO FOSSIL FUELS POSE TO UTILITY RATEPAYERS?

A. The primary financial risk that fossil fuels pose to utility ratepayers is significant price volatility, especially for gas. This volatility is driven by domestic as well as international supply and demand considerations, as I discuss below. Because approved fuel costs are typically passed through to ratepayers and recovered through fuel clause adjustments or "riders," like the one at issue in this proceeding, ratepayers are exposed to the risk of gas price increases.

Q: WHY DO YOU ONLY FOCUS ON THE FORECASTED IMPACT OF GAS PRICE SPIKE(S)?

A: From my review of the Company's discovery responses, DEC had 1,677 separate "Deal No." transactions recorded over the course of the Test Period and paid 689 different prices under those "deals." Prices change every day and month in the gas industry, which is reflected in the relevant daily and monthly markets. Moreover, as mentioned, ratepayers can be negatively impacted when these prices dramatically increase.

Q. PLEASE DISCUSS THE FACTORS THAT, IN YOUR VIEW, ARE CONTRIBUTING TO THE SIGNIFICANT, RECENT GAS PRICE INCREASES.

A. Fossil fuel prices, especially gas prices, are inherently volatile, and are subject to domestic—and increasingly, international—supply and demand factors.

Domestically, gas demand is the key driver. Demand for gas for power generation is relatively inelastic because there are few commercially viable substitutes other than aggressive adoption of renewable energy and storage. Indeed, given recent price volatility, even diesel oil is no longer a commercially viable substitute. Similarly, there has been slow adoption of economically viable substitutes for other gas end uses such as heating. Seasonal demand for gas is heavily weather dependent, both for heating and power generation. As Company witness Verderame notes, "stable production, lower than average storage inventory balances and seasonal weather demand" have contributed to recent gas price volatility.[4] In addition, the gas industry is capital-intensive, and it is difficult for gas suppliers to rapidly ramp up or scale down production in response to market signals.

Furthermore, in 2021, the U.S. economy, along with many other countries', finally began to recover from the economic downturn that dominated much of the beginning of the COVID-19 pandemic.[5] Resulting pent up commercial and industrial demand exerted significant upward pressure on gas prices. The U.S. is also projected to become the world's largest exporter of liquified natural gas ("LNG").[6] As domestic LNG

---

[4] Direct Testimony of John A. Verderame, page 8, lines 2-3.

[5] Scott Divasino, *U.S. natgas volatility jumps to a record as prices soar worldwide*, REUTERS (Oct. 7, 2021), https://www.reuters.com/business/energy/us-natgas-volatility-jumps-record-prices-soar-worldwide-2021-10-06/.

[6] Scott Divasino, *U.S. to be world's biggest LNG exporter in 2022*, REUTERS (Dec. 21, 2021), https://www.reuters.com/business/energy/us-be-worlds-biggest-lng-exporter-2022-2021-12-21/.

suppliers struggle to construct additional LNG plants and establish additional LNG export terminal capacity, "competition for limited . . . [existing LNG] exports increases,"[7] which in turn increases gas prices. In turn, financial markets struggle to respond to these domestic and international developments, which further exacerbates price volatility. In 2021, "the wholesale spot price for natural gas at the Henry Hub in Louisiana averaged $3.89 per million British thermal units (MMBtu) in 2021," which is almost double the 2020 average.[8]

Q. HOW LONG CAN RATEPAYERS EXPECT THESE PRICE INCREASES TO PERSIST?

A. For many reasons, ratepayers can expect these price increases to persist for the foreseeable future. However, for the sake of brevity, I will highlight just three reasons. First, Europe seeks to sharply reduce its Russian gas imports, which will likely mean increased U.S. LNG exports and the construction of additional U.S. export facilities to ensure the increased flow of U.S. LNG exports. Second, Marcellus/Utica producers in Southwestern Pennsylvania have been reluctant to increase production beyond the amount necessary to keep their pipeline capacity contracts full; this is because increasing production beyond that level would exceed their takeaway capacity and

---

[7] *Supra* note 5.
[8] U.S. Energy Information Admin., *U.S. natural gas prices spiked in February 2021, then generally increased through October* (Jan. 6, 2022), https://www.eia.gov/todayinenergy/detail.php?id=50778#:~:text=The%20wholesale%20spot%20price%20for,according%20to%20data%20from%20Refinitiv.

would, as a result, depress the prices they receive for the quantity of gas that exceeds their contracted takeaway capacity. Third, gas producers are using their profits from their gas sales to reduce their debts, pay shareholders dividends, or buy back stock.

IV. Risk Mitigation Strategies

Q. HOW CAN UTILITIES MITIGATE THEIR CUSTOMERS' EXPOSURE TO FOSSIL FUEL PRICE VOLATILITY?

A. Generally, utilities use hedging to help reduce volatility and to stabilize prices for a portion of their generation fuel supply. There are at least three ways in which a utility can hedge its fuel costs against price volatility. First, a utility could buy a financial instrument, such as a future on a regulated exchange. While these products do not provide the utility or the utility's customers with actual electricity, they do offer, for a limited portion of a utility's purchases, a means of either fixing a utility's purchased energy prices or offsetting the utility's energy costs with revenue from the financial product(s).

Second, a utility could purchase the option to buy a quantity of fuel over a specified time period. These transactions can be structured upfront as "costless" or "cost free" products if the utility adopts a collar strategy. Under this scenario, the utility would purchase a "call" option from a counterparty, which would then give the utility the right to purchase a specific quantity of gas at a specific price. The utility would then simultaneously sell a "put" option to that counterparty, which would give the counterparty the right to induce the Company to sell that same quantity of gas at a specific price. This collar strategy is effectively "free" and "costless" when each party agrees to set the floor and ceiling price in return for the same, offsetting payment. Accordingly, this strategy minimizes the utility's exposure to gas price increases. Should gas prices drop below the floor price of the collar, the utility will be required to buy gas at that floor price, or pay the counterparty an amount reflecting the difference between the floor price and the market price times the specified quantity. But again, this would involve only a limited portion of the utility's fuel purchases, leaving ratepayers exposed even under the most fortuitous of transactions.

Third, as discussed later in my testimony, a utility could employ "physical hedging" to protect ratepayers against the risk of fuel price volatility by procuring or self-building energy that has no fuel costs, such as wind or solar.

Q. WHAT ARE THE LIMITATIONS OF FINANCIAL HEDGING?

A. A utility cannot economically hedge its future fuel costs below forecasted prices (i.e., the prices the New York Mercantile Exchange ("NYMEX") and other exchanges present for the future period). Another limitation is that a utility must avoid "over-hedging." Said another way, a utility must ensure that it does not hedge a volume that exceeds its projected burn for the same time period the hedge would cover. At bottom, financial hedging can only reliably reduce volatility. It neither eliminates volatility nor permits a utility to secure future gas prices below forecasted, future prices.

PUBLIC VERSION
Confidential Information Redacted

Q. WHAT DO YOU CONCLUDE REGARDING THE IMPACT OF THE COMPANY'S HEDGING ACTIVITIES ON ITS INCURRED FUEL COSTS?

A. Based upon my review of the Company's discovery responses, I conclude that those volumes the Company chose to hedge appear to have delivered savings to the Company's customers. In addition, I conclude that even if the Company had hedged a greater portion of its purchases, it would not have fully insulated ratepayers from higher prices or volatility for the unhedged gas purchases. Importantly, these savings were only achieved because prices exceeded projections, and were largely the result of sustained commodity price increases in the Test Period when compared to the prices the sellers of those hedge products forecasted. This means that future savings might not be achieved and even losses would be realized if gas prices were stable at any level or decreased.

To further illustrate this point, when future gas prices are forecasted to be high and continue to be high relative to 2020 prices, which is currently the case, one cannot buy a hedge product below what the NYMEX indicates the price will be in the future. For instance, in mid-May 2020, the July 2022 price on the NYMEX was $2.365. In mid-May 2021, the July 2022 price on the NYMEX was $2.649. In mid-September 2021, the July 2022 price on the NYMEX increased to $3.797, and in mid-April 2022, the July 2022 price on the NYMEX had almost doubled to $6.839. As of Monday, May 16, 2022, the July 2022 price is $8.0530.

PUBLIC VERSION
Confidential Information Redacted

All this underscores the limits of financial hedging, which, it bears repeating, can only stabilize future prices or reduce, but not eliminate price volatility. Furthermore, as I have explained, a utility cannot economically hedge at prices below market forecasts.

Q: WHAT OTHER ASPECTS OF THE COMPANY'S HEDGING TRANSATIONS MERIT FURTHER DISCUSSION?

A: In my review of the Company's execution dates of its financial hedge transactions, I found that the latest execution date for any December 2021 Henry Hub hedge was in July 2020 and no Henry Hub hedges for any part of 2021 were executed after July 2020.

In addition, the latest hedge execution date for December 2021 Transco Zone 4 gas was in May 2021 and there were no other hedges for Transco Zone 4 gas executed after May 2021. Finally, the most recent execution date for a "costless collar" transaction was in September 2021 for December 2021.

Q: WHAT IS THE SIGNIFICANCE OF THESE DATES?

A: In mid-2020 and up through May and even September 2021, gas pricing in the U.S. and international gas markets was rather low, due in large part to depressed demand associated with the COVID-19 pandemic. The timing of those 2020 and 2021 hedge transaction executions and the value ratepayers received from them reflect the state of the gas market at the time of the executions. Put simply, the significance of these dates is that the 2020 hedges for 2021, along with the "costless collar" transactions for 2021, benefitted ratepayers precisely because gas prices increased. Hence, for the portion of the gas supply that the Company hedged, ratepayers benefitted but, for the roughly [redacted]% of supply that was purchased at the market price at the time (i.e., without offsetting hedges), ratepayers will now have to pay higher energy prices for electricity to recoup not only under-recoveries but also higher forecasted prices in the future. In short, fortuitous hedging helps, but it cannot entirely eliminate ratepayer exposure to rising and/or volatile fossil fuel prices, especially gas prices. As I discuss below however, a utility can potentially secure future energy prices through a physical hedging approach that both eliminates volatility and delivers lower prices than the NYMEX's current gas prices.

Q. YOU PREVIOUSLY DISCUSSED THE USE OF PHYSICAL HEDGING PRODUCTS TO MINIMIZE CUSTOMERS' EXPOSURE TO FOSSIL FUEL PRICE VOLATILITY. PLEASE ELABORATE.

A. Because wind and sunshine are free, there is no fuel price for wind energy and solar energy. Once wind turbine and solar panel investments have been made, the only variable costs are operations and maintenance costs, which can be fixed by contract. Conversely, investments in new gas-fired generation only fix capital costs and possibly maintenance. They do not fix energy costs and instead subject ratepayers to potential pass-throughs of fuel costs that are subject to market vagaries.

The U.S. Energy Information Administration ("EIA") released a 2022 report that estimates that the Levelized Cost of Energy ("LCOE") for different renewable energy resources.[9] The LCOE for utility scale wind, including tax credits, is $26.15 per MWh. For utility scale solar, the estimated LCOE, including tax credits, is $26.69 per MWh. Without tax credits, the LCOE is $34.92 per MWh for wind and $33.07 for solar. These estimates do not take into account financing costs, or utility returns in the event a regulated utility is making these investments. Nevertheless, these LCOE for wind and solarcompare quite favorably to the average cost per MWh for gas-generated energy, which over the January 2023 to January 2033 period has an estimated average cost to the Company of $35.01/MWh.[10] Moreover, the LCOE for Wind and Solar are not subject to the same price volatility, as they have zero fuel costs. These data points are presented in Figure GML-1, below.

[9] U.S. ENERGY INFORMATION ADMIN., LEVELIZED COSTS OF NEW GENERATION RESOURCES *IN THE ANNUAL ENERGY OUTLOOK 2022* 17 (2022), https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

[10] I calculated this figure by taking the NYMEX closing prices on May 6, 2022 for the period of January 2023 through January 2033 and averaging them. I then used the price difference between the average price per dth of the Company's delivered gas and the gas Company purchased "into the pipe" or $[redacted] per dth and added this difference (as an adder) to the NYMEX average price for only the estimated delivered gas portion of the Company's purchases (i.e., [redacted]%). Then, for this [redacted]% of the Company's purchased gas on a delivered basis, I multiplied the NYMEX price combined with the adder by 7.2 (an estimated annual average heat rate for the Company's baseload gas fired generation facilities) and multiplied that number by [redacted]%. Then for the [redacted]% of Company's purchased gas "into the pipe", I multiplied the NYMEX price (without the adder) by 7.2 and multiplied that number by [redacted]%. I then added those two amounts to get an estimated 100% of purchased gas to generate a MWh cost of $35.01/MWh on average from January 2023 through January of 2033.

Figure GML-1 – Comparison of Gas, Utility Scale Wind, and Utility Scale Solar Costs[11]

	Average Cost	LCOE – Without Credits	LCOE – With Tax Credits
Utility Scale Wind	N/A	$34.92/MWh	$26.15/MWh
Utility Scale Solar	N/A	$33.07/MWh	$26.69/MWh
Methane Gas	$35.01/MWh	N/A	N/A

Q. WHAT ARE SOME OF THE ADVANTAGES OF USING RENEWABLES AS PHYSICAL HEDGING PRODUCTS?

A. The Commission has previously recognized that renewable energy resources provide fuel hedging value:

> Renewable generation provides fuel price hedging benefits because a utility's purchase of energy from a [Qualifying Facility] reduces the amount of fuel the utility otherwise would need to purchase. In doing so, the Commission acknowledged that purchasing solar power can be seen as the equivalent of buying natural gas forwards. . . . the Commission finds that the evidence in this proceeding demonstrates again that there are fuel price hedging benefits associated with renewable generation. Purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that must be purchased and, therefore, the costs that the utilities would incur toward fuel procurement. . . . The Commission agrees with Cube Yadkin that the value of the hedge is to insulate ratepayers from

[11] These figures are drawn from the EIA's 2022 LCOE of new generation resources, *see* https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf, and my calculations, *see* supra note 8.

> fuel volatility, and that the hedge value is appropriate for inclusion in avoided cost rates.[12]

Although the Commission reached these findings in the context of determining utility avoided costs, the same logic applies here to the value that physical hedges, either from the procurement or construction of renewable energy resources, provide by supplying fuel-free power to DEC ratepayers.

Q. COULD DEC HEDGE A PORTION OF ITS ENERGY NEEDS BY PROCURING OR SELF-BUILDING WIND AND SOLAR GENERATION IN LIEU OF GAS GENERATION?

A. Yes. Wind and solar resources can not only fix the costs for a large portion of the Company's energy requirements, but also immunize the Company and its customers from gas price increases and spikes. To serve as effective fuel price hedges, of course, the wind and solar energy must either be purchased on a fixed price basis or generated by utility-owned facilities. Under either circumstance, the "fuel" costs are fixed at zero.

In short, in addition to providing capacity, energy, and other services to the electric grid, renewables provide hedging value, and the Commission should encourage the Company to obtain as much of that value as possible as part of the Company's comprehensive hedging strategy.

Q. YOU MENTIONED EARLIER THAT THERE WAS SOMETHING "MISSING FROM THE COMPANY'S FUEL COST PLANNING AND FORECASTING PRACTICES." PLEASE ELABORATE.

---

[12] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 158, (April 15, 2020).

PUBLIC VERSION
Confidential Information Redacted

A: An important element that is missing from the Company's fuel cost planning and forecasting practices is an additional forecast that measures and projects the impact on consumer bills of future fuel price spikes(s) if such spike (s) were to occur in the billing period used to establish the fuel factor.

The Company's fuel factor is based upon the net effect of two elements. One is the amount of over or under recovery during the test period. At a high level, the second element is the forecasted set of prices and purchases (i.e., forecasted, total cost of fuel) for the billing period. The sum of these two numbers, again at a high level, is then divided by the number of forecasted sales in the billing period to calculate a fuel factor that is applied to each sale(s) unit.

The purpose of this forecast would be to provide the Commission with a preview of the potential impact of such projected fuel price spike(s) and help inform the Company's strategy to reduce or mitigate its customers' exposures to future, projected price spikes.

Q. WHAT SPECIFIC RECOMMENDATIONS WOULD YOU THEN PROPOSE TO IMPROVE DUKE'S FUEL COST PLANNING AND FORECASTING PRACTICES?

A. The Commission should require the Company to incorporate the impact of periodic gas fuel price spikes into the Company's forecasted fuel costs. Specifically, the Company's planning and forecasting should incorporate the frequency, duration, and magnitude of prior upward fuel price departures of 15% or greater from the average price and use this historical data to inform its

PUBLIC VERSION
Confidential Information Redacted

projections of the frequency, duration, and magnitude of future price spikes, along with the potential impacts of these future price spikes on customers if they were to recur. For instance, the Company could use trailing ten-years price spikes as the source data. The Company should then incorporate these projected impacts and compare them with its primary projections in future fuel charge adjustment proceedings.

Q. WHAT ADDITIONAL INFORMATION WOULD YOU RECOMMEND DEC FILE IN FUTURE FUEL CHARGE ADJUSTMENT PROCEEDINGS IN LINE WITH THESE RECOMMENDATIONS?

A. I recommend that with each future fuel charge adjustment filing, the Company should provide the prior period's month by month forecasts, specifically, both the average price forecast and a forecast incorporating the impact of potential, future price spike(s). This would enable comparisons (i.e., variances) to be made and would help both the Company and the Commission determine whether these variances were because the average prices varied or because prices were volatile.

V. Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS WITH RESPECT TO DEC'S REQUESTED FOSSIL FUEL AND FUEL-RELATED COSTS.

A. The Company's under-recovery of its fuel and fuel-related costs can be attributed in part to its gas price projections being lower than the actual market prices during the Test Period. These under-projections, among other things, will have significant bill impacts for DEC ratepayers, and are partially responsible for the estimated $9.85 increase to DEC monthly residential bills, assuming the Commission approves the Company's fuel charge adjustment application.

While all fossil fuels are inherently volatile, gas is particularly so due to domestic and international demand and supply considerations. Given this, financial hedging strategies can only mitigate customer exposure to this volatility in the short term, but cannot reliably reduce fuel prices over the long-term (i.e., over the period covered by investments in fuel-free generation).

To further mitigate customer exposure to fossil fuel price volatility, I would recommend that DEC forecast the impact of periodic deviations of at least 15% or greater from average gas prices on customer bills. Specifically, I would propose that the Company use trailing ten-years data of gas price spike(s) to inform its projections on the frequency, duration, and magnitude of future price spike(s). In future fuel charge adjustment proceedings, the Company should provide month by month fuel price forecasts that include the average gas price forecast and a "15%" or greater price spike forecast. This strategy would help the Company plan its response to future gas price volatility and help the Commission evaluate the Company's volatility mitigation strategies.

Lastly, the Company should use wind and solar energy to the fullest extent possible to hedge against fossil fuel price volatility. Depending on how these assets are structured, wind and solar energy facilities can supply a large portion of the Company's generation needs at a fixed cost, with little to no exposure to fossil fuel price volatility.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CHAIR MITCHELL: With that, we are concluded with the expert witness hearing. We will take proposed orders 30 days from the notice of the mailing of the transcript. Anything else, counsel?

MR. KAYLOR: Thank you, no.

CHAIR MITCHELL: Thank you-all. We are adjourned. Let's go off the record, please.

(The proceedings were adjourned)

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