PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, September 9, 2019

TIME: 4:10 p.m. - 5:01 p.m.

DOCKET NO: E-2, Sub 1204

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

IN THE MATTER OF:

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

VOLUME 1

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

FOR DUKE ENERGY PROGRESS, LLC:

Jack Jirak, Esq.
Associate General Counsel
410 S. Wilmington Street/NCRH 20
Raleigh, North Carolina 27602

Dwight Allen, Esq.
Allen Law Offices, PLLC
1514 Glenwood Avenue
Raleigh, North Carolina 27608

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

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

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES, II:

Ralph McDonald, 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 SIERRA CLUB:
Gudrun Thompson, Esq.
Senior Attorney
Tirrill Moore, Esq.
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR FAYETTEVILLE PUBLIC WORKS COMMISSION:
James West, Esq.
General Counsel
955 Old Wilmington Road
Fayetteville, North Carolina 28301

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Benjamin Smith, Esq.
Regulatory Counsel
4600 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

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

FOR THE USING AND CONSUMING PUBLIC:

Dianna Downey, 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 H I B I T S

P R O C E E D I N G S

E-2, Sub 1204 Volume 1 - Partial confidential

MS. MITCHELL: Good afternoon. Let's come to order and go on the record, please. I'm Charlotte Mitchell, the Chair of the Utilities Commission, and with me this afternoon are Commissioners ToNola D. Brown-Bland, Lyons Gray and Daniel G. Clodfelter.

I now call for hearing Docket Number E-2, Sub 1204, which is the Application by Duke Energy Progress, 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.

On June 11th, 2019, Duke filed its Application to adjust the fuel and fuel-related cost component of electric rates with supporting testimony and exhibits and workpapers of Dana Harrington, and the testimony and exhibits of Regis Repko, Kenneth Church, Kelvin Henderson and Brett Phipps.

On June 20th, 2019, the Commission issued its Order Scheduling Hearing, Requiring the Filing of Testimony, Establishing Discovery Guidelines and Requesting Public Notice.

On August 15th, 2019, Duke filed additional testimony and exhibits stating that based on an update of its fuel cost through June 30th, 2019, an increase in the residential and non-residential fuel rates initially included in its Application is necessary.

On August 23rd, 2019, Duke filed a request to publish a second public notice to inform ratepayers of the change in the proposed fuel rates.

And on August 26th, 2019, the Commission issued an Order Requiring the Publication of a Second Public Notice.

On August 19th, 2019, the Public Staff filed the testimony and exhibits of Jay Lucas, Dustin Metz, and Jenny Li.

On August 28th, 2019, Duke filed the rebuttal testimony of Witness Kelvin Henderson, Barbara Coppola, and John Halm.

Petitions to Intervene have been filed by and granted to Fayetteville Public Works Commission, North Carolina Electric Membership Corporation, Carolina Utility Customers Association, Inc., North Carolina Sustainable Energy Association, the Sierra Club, and Carolina Industrial Group for Fair Utility Rates II.

On September 5th, 2019, the Public Staff filed a motion requesting that witnesses Metz and Li be excused from attending the expert witness hearing.

Also on September 5th, 2019, Duke filed a motion requesting that witnesses Repko, Church and Henderson be excused from attending the expert witness hearing.

All parties have agreed to waive cross examination of these witnesses.

On September 6th, 2019, the Commission issued -- the Commission ordered that the Public Staff witnesses Metz and Li and Duke's witnesses Repko, Church, and Henderson all be excused from appearing at this hearing, and that the testimony and exhibits of the respective witnesses be received into evidence.

Pursuant to the State Ethics Act, I remind all members of the Commission of their duty to avoid conflicts of interest and inquire at this time as to whether any Commissioner has a known conflict of interest with respect to the matters appearing before us this afternoon?

(No response)

Please let the record reflect that there are no such conflicts. So we will move forward with the proceeding, and I now call upon counsel for the parties to announce their appearances, beginning with the Applicant.

MR. JIRAK: Good afternoon, Chair Mitchell and Commissioners. Jack Jirak and Dwight Allen on behalf of Duke Energy Progress.

CHAIR MITCHELL: Good afternoon, Mr. Jirak.

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

MR. PAGE: Robert Page on behalf of Carolina Utility Customers Association.

MR. McDONALD: Ralph McDonald for the Carolina Industrial Group for Fair Utility Rates II.

MR. WEST: James West appearing on behalf of the Fayetteville Public Works Commission. Good afternoon.

MS. THOMPSON: Good afternoon, Chair Mitchell. Members of the Commission, Gudrun Thompson appearing on behalf of the Sierra Club, and with me, also appearing on behalf of Sierra Club, is Tirrell Moore.

MS. DOWNEY: Good afternoon, Commissioners. Dianna Downey representing the Public Staff and representing the Using and Consuming Public.

CHAIR MITCHELL: Thank you. Are there any preliminary matters that we must take up before we move into the hearing? Mr. West.

MR. WEST: If I could raise just one, if I could, which is I believe that the intervenors have confidential exhibits. I don't know who has or has not signed an NDA. I think we can probably rely on Duke to identify who can and cannot receive, but the outcome of that may be that we need to go in and out of closed session several times.

CHAIR MITCHELL: Thank you, Mr. West. If attorneys would please alert me when you intend to ask questions on confidential information and we will clear the room at that time for anyone who is not under NDA with the Applicant.

MS. THOMPSON: Yes. And, Chair Mitchell, I'll just go ahead, I believe the Company is putting its witness Brett Phipps up first. I do have questions for Mr. Phipps that are on confidential exhibits starting with my very first question.

CHAIR MITCHELL: Thank you, Ms. Thompson.

Any other preliminary matters?

MR. JIRAK: And on that topic, all -- I believe that all intervenor parties have executed Confidentiality Agreements. Obviously, the terms of the Confidentiality Agreement requires acknowledgment who are seeking to access the confidential information so, as far as parties go, we're aware to the extent that we have not received it for a particular individual from an intervenor, that particular intervenor even if you're with that -- individuals with the intervenor that's executed the confidentiality would need to not be present for cross examination on those topics.

CHAIR MITCHELL: I trust that, Mr. Jirak, that you can handle that when the issue arises.

MR. JIRAK: Very good.

CHAIR MITCHELL: Okay. Ms. Downey, has the Public Staff identified any public witnesses that are here this afternoon to present testimony.

MS. DOWNEY: No, ma'am.

CHAIR MITCHELL: Are there any -- anyone in the audience that wishes to present public testimony this afternoon?

(No response)

It does not appear that anyone wishes to present testimony so we will proceed with the case. I call on Duke to present its evidence.

MR. JIRAK: Thank you. Chair Mitchell, as you noted the Commission's September 6th, 2019, Order excused a number of witnesses from appearing and also noted that the testimony of those particular witnesses would be received in the record. And, out of an abundance of caution, I would now move the testimony of Regis Repko, Kenneth D. Church, and Kelvin Henderson, along with the relevant exhibits, into evidence at this time.

CHAIR MITCHELL: Hearing no objection your motion is allowed.

MR. JIRAK: Thank you.

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

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

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

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

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

A. Yes. I testified before this Commission in the DEP NC 2015 Fuel Hearing Docket E-2, Sub 1069.

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

A. The purpose of my testimony is to (1) describe DEP's Fossil/Hydro/Solar generation portfolio and changes made since the 2018 fuel and fuel-related cost recovery proceeding, as well as those expected in the near term, (2) discuss the performance of DEP's Fossil/Hydro/Solar facilities during the test period of April 1, 2018 through March 31, 2019 (the "test period"), (3) provide information on significant Fossil/Hydro/Solar outages that occurred during the test period, and (4) provide information concerning environmental compliance efforts.

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

A. The Company's Fossil/Hydro/Solar generation portfolio consists of 9,204 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	3,544 MWs
Combustion Turbines -	2,816 MWs
Combined Cycle Turbines -	2,568 MWs
Hydro -	227 MWs
Solar -	49 MWs[1]

[1] This value represents the relative dependable capacity contribution to meeting summer peak demand, based on the Company's integrated resource planning metrics. The nameplate capacity of the Company's solar facilities is 141 MWs.

The 3,544 MWs of coal-fired generation represent the three generating stations of Roxboro, Mayo, and Asheville, which total seven units. These units are equipped with emission control equipment, including selective catalytic reduction ("SCR") equipment for removing nitrogen oxides ("NO_x"), flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"), and low NO_x burners. This inventory of coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content – providing flexibility for DEP to procure the most cost-effective options for fuel supply.

The Company has a total of 32 simple cycle combustion turbine ("CT") units, the larger 14 of which provide 2,183 MWs, or 78% of CT capacity. These 14 units are located at Asheville, Darlington, Richmond County, and Wayne County facilities, and are equipped with water injection systems that reduce NO_x and/or have low NO_x burner equipment in use. The 2,568 MWs shown as "Combined Cycle Turbines" ("CC") represent four power blocks. The H.F. Lee Energy Complex CC power block ("Lee CC") has a configuration of three CTs and one steam turbine. The two Richmond County power blocks located at the Smith Energy Complex consist of two CTs and one steam turbine each. The Sutton Combined Cycle at Sutton Energy Complex ("Sutton CC") consists of two CTs and one steam turbine. The four CC power blocks are equipped with SCR equipment, and all nine CTs have low NOx burners. The steam turbines do not combust fuel and, therefore, do not require NOx controls. The Company's hydro fleet consists of 15 units providing 227 MWs of capacity. The Company's solar fleet consists of four sites providing 49 MWs of dependable capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEP'S 2018 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. Darlington CT Unit 5 retired in May 2018, which reduced capacity by 51 MWs.

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

A. The primary objective of DEP's Fossil/Hydro/Solar generation department is to provide safe, reliable and cost-effective electricity to DEP'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 DEP's customers. Equipment inspection and maintenance outages are generally scheduled during the spring and fall months when customer demand is reduced due to milder temperatures. These outages are well-planned and executed in order to prepare the unit for reliable operation until the next planned outage in order to maximize value for customers.

Q. WHAT IS HEAT RATE?

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

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

A. Over the test period, the Company's seven coal units produced 25% of the Fossil/Hydro/Solar generation, with the average heat rate for the coal-fired units being 11,352 Btu/kWh. The most active station during this period was Roxboro, providing 68% of the coal production for the fleet with a heat rate of 10,624 Btu/kWh. During the test period, the Company's four combined cycle power blocks produced 59% of the Fossil/Hydro/Solar generation, with an average heat rate of 7,167 Btu/kWh.

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

A. For the test period, DEP's total system generation was 60,144,861 megawatt-hours ("MWHs"), of which 32,396,712 MWHs, or approximately 54%, was provided by the Fossil/Hydro/Solar fleet. The breakdown includes a 39% contribution from gas facilities, 14% contribution from coal-fired stations, 1.4% contribution from hydro facilities, and 0.4% from solar facilities.

The Company's portfolio includes a diverse mix of units that, along with its nuclear capacity, allows DEP to meet the dynamics of customer load requirements in a logical and cost-effective manner. Additionally, DEP has utilized the Joint Dispatch Agreement with Duke Energy Carolinas, LLC

("DEC"), which allows generating resources for DEP and DEC to be dispatched as a single system to enhance dispatching at the lowest possible cost. The cost and operational characteristics of each unit generally determine the type of customer load situation (e.g., base and peak load requirements) that a unit would be called upon or dispatched to support.

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

A. The Company, like other utilities across the U.S., has experienced a change in the dispatch order for each type of generating facility due to continued favorable economics resulting from the lower pricing of natural gas. Further, the addition of new CC units within DEP's portfolio in recent years has provided DEP with additional natural gas resources that feature state-of-the-art technology for increased efficiency and significantly reduced emissions. These factors promote the use of natural gas and provide real benefits in cost of fuel and reduced emissions for customers. Gas fired facilities provided 59% of the DEP Fossil/Hydro/Solar generation during the test period.

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

A. The Company's generating units operated efficiently and reliably during the test period. Several 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 maintenance (*i.e.*, forced) outage time); (2) net capacity factor ("NCF"), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF *is* affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate ("EFOR"), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and, (4) starting reliability ("SR"), which represents the percentage of successful starts.

The following chart provides operational results categorized by generator type, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") representing the period 2013 through 2017. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating.

Generator Type	Measure	Review Period DEP Operational Results	2013-2017 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	71.4%	81.6%	418
	NCF	25.9%	57.8%	
	EFOR	6.1%	8.1%	
Coal-Fired Summer Peak	EAF	93.1%	n/a	n/a
Total CC Average	EAF	80.3%	85.0%	338
	NCF	72.5%	52.7%	
	EFOR	4.77%	5.3%	
Total CT Average	EAF	80.2%	87.8%	776
	SR	98.7%	98.1%	
Hydro	EAF	79.7%	80.4%	1,113

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

A. In general, planned maintenance outages for all fossil and hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most units had at least one short planned outage during this review period to inspect and maintain plant equipment.

Roxboro Unit 4 had a planned outage in Spring 2018. The primary purpose of the outage was to perform major boiler maintenance and precipitator maintenance. Mayo Unit 1 had a planned outage in Fall 2018 to replace the generator breaker and perform minor boiler maintenance. Roxboro Unit 2 had a planned outage in Fall 2018. The primary purpose of the outage was to replace burners, perform MATS inspection, and tie-in the dry bottom ash system.

The CC fleet performed planned outages at Richmond County CC PB5 and Sutton CC in Spring 2018. The primary purposes of the Richmond CC PB5 outage was to perform borescope inspections on the combustion turbines and steam turbine, perform a Heat Recovery Steam Generator ("HRSG") inspection, and balance of plant equipment maintenance. The primary purpose of the Sutton CC outage was to perform a hot gas path inspection of the combustion turbines.

The CT fleet performed planned outages in Spring and Fall 2018. In Spring 2018, Smith CT Unit 1 and Unit 2 had planned outages. The primary purpose of the Smith CT Unit 1 outage was to replace the existing exhaust stack. The primary purpose of the Smith CT Unit 2 outage was to rewind the generator rotor, perform a hot gas path inspection, and replace the existing exhaust stack. In Fall 2018, Asheville CT Unit 3 and Unit 4 had a planned outage to perform transmission work in the switchyard for the new Asheville CC plant and to perform balance of plant maintenance.

Q. HOW DOES DEP ENSURE EMISSIONS REDUCTIONS FOR ENVIRONMENTAL COMPLIANCE?

A. The Company has installed pollution control equipment on coal-fired units, as well as new generation resources, in order to meet various current federal, state, and local reduction requirements for NOx and SO2 emissions. The SCR technology that DEP currently operates on the coal-fired units uses ammonia or urea for NOx removal and the scrubber technology employed uses crushed limestone or lime for SO2 removal. SCR equipment is also an integral part of the design of the newer CC facilities in which aqueous ammonia (19% solution of NH_3) is introduced for NOx 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 and utilization of non-traditional coals. Overall, the goal is to effectively comply with emissions regulations and provide the optimal total-cost solution for operation of the unit. The Company will continue to leverage new technologies and chemicals to meet both present and future state and federal emissions requirements including the Mercury and Air Toxics Standards ("MATS") rule. Company witness Harrington provides the cost information for DEP's chemical use and forecast.

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

A. Yes, it does.

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

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kenneth D. Church 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 General Manager of Nuclear Fuel Engineering for Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEP?

A. I am responsible for nuclear fuel procurement and spent fuel management, as well as the fuel mechanical design, reactor core design, probabilistic risk assessment, and safety analysis for the nuclear units owned and operated by DEP and DEC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from North Carolina State University with a Bachelor of Science degree in mechanical engineering. I began my career with DEC in 1991 as an engineer and worked in various roles, including nuclear fuel assembly and control component design, fuel performance, and fuel reload engineering. I assumed the commercial responsibility for purchasing uranium, conversion services, enrichment services, and fuel fabrication services at DEC in 2001. Beginning in 2011, I incrementally assumed responsibility at DEC for spent nuclear fuel management along with the nuclear fuel mechanical design and reload licensing analysis functions. Subsequently, I assumed the same responsibilities for DEP following the merger between Duke Energy Corporation and Progress Energy, Inc. before entering my current position in January of 2019.

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, and have also served as Chairman of the World Nuclear Fuel Market's Board of Governors, an organization that promotes efficiencies in the nuclear fuel markets. I am currently a registered professional engineer in the state of North Carolina.

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

A. The purpose of my testimony is to: (1) provide information regarding DEP's nuclear fuel purchasing practices (2) provide costs for the April 1, 2018 through March 31, 2019 test period ("test period"), and (3) describe changes forthcoming for the December 1, 2019 through November 30, 2020 billing period ("billing period").

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

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

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

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

DEP's portfolio of diversified contract pricing yielded an average unit cost of $41.38 per pound for uranium concentrates during the test period, representing an increase of 42% per pound from the prior test period. This increase was primarily due to the purchase of low cost uranium available in the spot market during the prior test period.

A majority of DEP's enrichment purchases during the test period were delivered under long-term contracts negotiated prior to the test period. The average unit cost of DEP's purchases of enrichment services during the test period decreased 8% to $93.22 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 – 22% and 5%, respectively, for the fuel batches recently loaded into DEP's reactors – of DEP's total direct fuel cost relative to uranium concentrates or enrichment, which each represent 43% and 30%, respectively, of the total.

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

A. Prices in the uranium concentrate markets remain relatively low due to reduced demand following the March 2011 event at Fukushima. Industry consultants believe that recent production cutbacks have been warranted due to the previously existing oversupply conditions and that market prices need to 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 enrichment and conversion 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 DEP'S NUCLEAR FUEL COST IN THE BILLING PERIOD?

A. The Company anticipates a decrease in nuclear fuel costs on a cents per kilowatt hour ("kWh") basis through the next billing period. Because fuel is typically expensed over two to three operating cycles (roughly three to six years), DEP'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 contribute to a portion of the uranium, conversion, enrichment, and fabrication costs reflected in the total fuel expense.

The average fuel expense is expected to decrease from 0.656 cents per kWh incurred in the test period, to approximately 0.617 cents per kWh in the billing period. This change reflects the discharge of fuel with a higher cost basis from the reactors and its replacement with fuel procured under new contracts negotiated in lower markets.

Q. WHAT STEPS IS DEP 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 Church Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEP 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, DEP'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 mitigating DEP'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 DEP'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, Henderson Confidential Exhibit 1 is marked for identification as prefiled and received into evidence.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy") with direct executive accountability for Duke Energy's North Carolina nuclear stations, including Duke Energy Progress, LLC's ("DEP" or the "Company") Brunswick Nuclear Station ("Brunswick") in Brunswick County, North Carolina, the Harris Nuclear Station ("Harris") in Wake County, North Carolina, and Duke Energy Carolinas, LLC's ("DEC") McGuire Nuclear Station, located in Mecklenburg County, North Carolina.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor's degree in Mechanical Engineering from Bradley University and over 27 years of nuclear energy experience with increasing responsibilities. My nuclear career began at Commonwealth Edison's Zion Nuclear Station in Illinois where I received a senior reactor operator license from the Nuclear Regulatory Commission ("NRC") and served as a control room unit supervisor. In 1998, I joined Progress Energy in the operations department at the Harris Nuclear Station. After serving in various leadership roles in Operations, Work Management, and Maintenance, I was named plant manager at Harris. In 2011, I was named general manager of nuclear fleet operations for Progress Energy. Following the Duke Progress merger in 2012, I became site vice president of DEC's Catawba Nuclear Station in York County, South Carolina. In 2016, I was named senior vice president of corporate nuclear, and I assumed my current role as Senior Vice President of Nuclear Operations in December 2017.

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

A. Yes, I provided testimony in DEP's 2018 fuel case proceeding in Docket No. E-2, Sub 1173.

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 Brunswick, Harris, and Robinson for the period of April 1, 2018 through March 31, 2019 (the "test period"). I will provide information about refueling outages for the test period and also discuss the nuclear capacity factor being proposed by DEP for use in this proceeding in determining the fuel factor to be reflected in rates during the billing period of December 1, 2019 through November 30, 2020 ("billing period").

Q. PLEASE DESCRIBE EXHIBIT 1 INCLUDED WITH YOUR TESTIMONY.

A. Exhibit 1 is a confidential exhibit outlining the planned schedule for refueling outages for DEP's nuclear units through the billing period. This exhibit represents DEP's current plan, which is subject to adjustment due to changes in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEP'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 3,575[1] megawatts ("MWs") of generating capacity, made up as follows:

Brunswick -	1,870 MWs
Harris -	964 MWs
Robinson -	741 MWs

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF DEP'S NUCLEAR GENERATION ASSETS.

A. The Company's nuclear fleet consists of three generating stations and a total of four units. Brunswick is a boiling water reactor facility with two units and was the first nuclear plant built in North Carolina. Unit 2 began commercial operation in 1975, followed by Unit 1 in 1977. The operating licenses for Brunswick were renewed in 2006 by the NRC, extending operations up to 2036 and 2034 for Units 1 and 2, respectively. Harris is a single unit pressurized water reactor that began commercial operation in 1987. The NRC issued a renewed license for Harris in 2008, extending operation up to 2046. Robinson is also a single unit pressurized water reactor that

[1] As of January 1, 2019.

began commercial operation in 1971. The license renewal for Robinson Unit 2 was issued by the NRC in 2004, extending operation up to 2030.

Q. WERE THERE ANY CAPACITY CHANGES WITHIN DEP'S NUCLEAR PORTFOLIO DURING THE TEST PERIOD?

A. Yes. Efficiency gains from the replacement of the Harris low pressure turbine in the spring of 2018 increased the capacity of the unit. After seasonal observations and validation testing, the Harris maximum dependable capacity ("MDC") was increased by 32 MWs to 964 MWs effective January 1, 2019. The winter capability rating was also increased, adding 29 MWs to the unit's winter capability.

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

A. The primary objective of DEP's nuclear generation department is to safely provide reliable and cost-effective electricity to DEP'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 DEP'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 46% of the total power generated by DEP. The four nuclear units operated at an actual system average capacity factor of 89.21% during the test period, which included three refueling outages.[2] Output from three of the four DEP nuclear units was significantly impacted during the test period by Hurricane Florence. Consistent with site procedures, both Brunswick units were taken offline prior to the expected landfall of Hurricane Florence. Brunswick Unit 1 was offline for 8.8 days and Unit 2 was offline for 6.3 days. After the Federal Emergency Management Agency ensured normal emergency recovery capabilities had been restored in the area, both Brunswick units returned to service. Additionally, the availability of Robinson was impacted by Hurricane Florence. As described later in my testimony, the Robinson refueling outage, which began one week after the hurricane's landfall, was impacted by resource constraints directly attributable to the hurricane and its aftermath.

The performance results discussed in my testimony demonstrate DEP's continued commitment to achieving high performance without compromising safety and reliability.

Q. HOW DOES THE PERFORMANCE OF DEP'S NUCLEAR FLEET COMPARE TO INDUSTRY AVERAGES?

[2] Brunswick Unit 2 entered a refueling outage on March 2, 2019 and remained offline at the end of the test period.

A. The Company's nuclear fleet has a history of exceptional 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 industry average capacity factor of 91.8% for comparable units for the five-year period 2013 through 2017. During the five-year period ending March 31, 2019, DEP's nuclear fleet achieved an average capacity factor of 93.29% compared to the industry average of 91.8%. DEP's two-year average[3] of 92.44% also exceeded the NERC comparable average of 91.8%. The Company's test period capacity factor of 89.21%, impacted by Hurricane Florence, fell just below the industry five-year average.

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

A. In general, refueling requirements, maintenance requirements, prudent maintenance practices, and NRC operating requirements impact the availability of DEP's nuclear system. Prior to a planned outage, DEP develops a detailed schedule for the outage including major tasks to be performed along with sub-schedules for particular activities.

The Company's scheduling philosophy is to plan for a best possible outcome for each outage activity within the outage plan. For example, if the "best ever" time a particular outage task was performed is 10 days, then 10 days or less becomes the goal for that task in each subsequent outage. Those individual goals are

[3] This represents the simple average for the current test period and prior test period of 12 months ended March 2018 for the DEP nuclear fleet.

incorporated into an overall outage schedule. The Company aggressively works to meet, and measures itself against, that schedule. Further, to minimize potential impacts to outage schedules, "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. Those discovery activities also have pre-planned contingency actions to ensure that, when incorporated into the schedule, the activities required for appropriate repair can be performed as efficiently as possible.

As noted, the Company uses the schedule for measuring outage planning and execution, and driving continuous improvement efforts. However, in order to provide reasonable, rather than best ever, total outage time for planning purposes, particularly with the dispatch and system operating center functions, DEP also develops an allocation of outage time which 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 DEP HANDLE OUTAGE EXTENSIONS AND FORCED OUTAGES?

A. When an outage extension becomes necessary, DEP seeks to ensure that work completed in the extension results in longer continuous run times and fewer forced outages, thereby reducing fuel costs in the long run. Therefore, if an unanticipated issue that has the potential to become an on-line reliability issue 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 usually extended to perform necessary maintenance or repairs prior to returning the unit to service. 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 DEP PERFORM POST-OUTAGE CRITIQUES AND CAUSE ANALYSES FOR INTERNAL IMPROVEMENT EFFORTS?

A. Yes. DEP 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 in order to identify areas in which it can utilize a self-critical analysis to drive further 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 REFUELING OUTAGES WERE COMPLETED AT DEP'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. There were two refueling outages completed during the test period: Harris and Robinson.

The Harris spring refueling outage began on April 7, 2018. In addition to refueling activities, safety, regulatory projects and reliability enhancements were completed. Safety and regulatory work included reactor vessel head inspections and repair, and reactor vessel in-service inspections. Replacement of the station's low-pressure turbine addressed the aging of the existing turbine and mitigated the free-standing blade root cracking concerns. The new turbine also improved thermal efficiency and added 32 MWs to the station's capacity. After testing and validation during 2018, the station's maximum dependable capacity was increased by 32 MWs to 964 MWs effective January 1, 2019. The station also completed installation of a new turbine control system. The new system addresses equipment obsolescence and single-point vulnerabilities, enhancing the reliability of the station. Other reliability work included refurbishment of the "B" reactor coolant pump motor and seals, "A" heater drain pump and motor, and overhaul of the auxiliary feed water turbine. All outage goals were met, and outage dose was the lowest ever recorded for a Harris refueling outage. After refueling, projects, maintenance, and inspection activity completed, the unit returned to service on May 10, 2018; a duration of 33.8 days compared to a schedule allocation of 37 days.

The Robinson refueling outage was originally scheduled to begin on September 15, 2018, just one day after Hurricane Florence made landfall along North Carolina's southeast coast. The outage start was delayed by one week, and on September 22, 2018, Robinson entered the fall refueling outage. In addition to refueling activities, significant safety, regulatory, and reliability enhancements were completed. Regulatory and safety enhancements included the transmission upgrade project ("TUP") and modifications required to transition to the NFPA 805. Significant activities associated with the TUP included replacement of the 115KV startup transformer, addition of a second 230KV startup transformer, and upgrades to the 4KV bus and transmission lines. The TUP provides the station with a second off-site power path, aligning the station with the current industry standard for U.S. nuclear plants. NFPA 805 modifications included replacement of refueling water storage tank discharge values, residual heat removal loop isolation valves, and loops "B" and "C" hotleg shutoff valves. Numerous new motor control centers and distribution panels were also installed as part of the NFPA 805 modifications. A main power open phase detection modification was also completed. This system improves safety margins related to offsite power by providing a fully redundant open phase protection system.

Reliability enhancements included the replacement of both low-pressure turbines, which addressed blade design issues that have impacted generation since 2012. The Siemens low-pressure turbines were replaced under warranty. Other reliability enhancements included replacement of the "B" reactor coolant pump motor and seal replacements on "A', "B", and "C" pumps. The "B" heater drain pump was also replaced.

After refueling, maintenance, projects and inspection activities were completed, the unit returned to service on November 26, 2018. The 65-day outage extended beyond the schedule allocation of 37 days, with the overrun primarily attributable to direct impacts on resource availability related to Hurricane Florence and challenges with the complex transmission upgrade project.

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

A. The Company proposes to use a 94.62% capacity factor, which is a reasonable value for use in this proceeding based upon the operational history of DEP'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 Harrington and exceeds the five-year industry weighted average capacity factor of 91.8% for comparable units as reported in the NERC Brochure during the period of 2013 to 2017.

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

A. Yes, it does.

MR. JIRAK: And, in addition, we would like to move the Application itself into the record as well.

CHAIR MITCHELL: The motion is allowed.

(WHEREUPON, Application by Duke Energy Progress is received into evidence.)

MR. JIRAK: Thank you. At this time I would call to the witness stand Brett Phipps on behalf of Duke Energy Progress.

CHAIR MITCHELL: Good afternoon, Mr. Phipps.

THE WITNESS: Good afternoon.

BRETT PHIPPS;

having been duly sworn,

testified as follows:

CHAIR MITCHELL: Thank you.

COMMISSIONER GRAY: Pull that microphone towards you.

THE WITNESS: I speak a little louder but I'll make sure --

COMMISSIONER GRAY: I'm still old.

THE WITNESS: I got you. Hopefully that's better.

DIRECT EXAMINATION BY MR. JIRAK:

Q Mr. Phipps, will you please begin by stating your full name and title for the record?
A My name is Brett Phipps. I'm the Managing Director of fuel procurement.
Q Thank you. Mr. Phipps, did you prepare and cause to be filed in this proceeding direct testimony consisting of eight pages of testimony and three exhibits?
A I did.
Q And, Mr. Phipps, do you have any changes to make to your direct testimony at this time?
A I do. On page 6, line 18 of my testimony, the value that's there of $66.12 should be updated to reflect $65.43.
Q Thank you. And, Mr. Phipps, aside from that correction, if I were to ask you the same questions contained in your testimony today, would your answers remain the same?
A Yes.

MR. JIRAK: Chair Mitchell, at this time I would request that the prefiled direct testimony and exhibits and workpapers (sic) of Brett Phipps be copied into the record as if given orally from the stand.

CHAIR MITCHELL: The motion is allowed filed.

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

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

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

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR

PROCEEDING?

A. Yes. I testified in support of DEP's 2016 fuel and fuel-related cost recovery application in Docket No. E-2, Sub 1146 and in May of 2017, I adopted the testimony filed by Swati V. Daji in support of DEC's 2016 fuel and fuel-related cost recovery application in Docket No. E-7, Sub 1129.

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

A. The purpose of my testimony is to describe DEP's fossil fuel purchasing practices, provide actual fossil fuel costs for the period April 1, 2018 through March 31, 2019 ("test period") versus the period April 1, 2017 through March 31, 2018 ("prior test period"), and describe changes projected for the billing period of December 1, 2019 through November 30, 2020 ("billing period").

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

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Phipps Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Phipps Exhibit 2, which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases for the test period and prior test period, and Phipps Exhibit 3, which summarizes the 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, of which DEP receives an allocated portion based on its pro rata share of the overall gas plant burns for the respective month.

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

A. Both DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically committed and dispatched to serve their respective customers. To that end, both companies consider numerous factors such as the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

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

A. The Company's average delivered cost of coal per ton for the test period was \$84.81 per ton, compared to \$80.82 per ton in the prior test period, representing an increase of approximately 5%. This includes an average transportation cost of \$32.72 per ton in the test period, compared to \$29.42 per ton in the prior test period, representing an increase of approximately 11%. The Company's average price of gas purchased for the test period was \$4.05 per Million British Thermal Units ("MMBtu"), compared to \$4.68 per MMBtu in the prior test period, representing a decrease of approximately 13%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEP's coal burn for the test period was 3.6 million tons, compared to a coal burn of 3.9 million tons in the prior test period, representing a decrease of approximately 7%. The Company's natural gas burn for the test period was 182.4million MMBtu, compared to a gas burn of 169.4 million MMBtu in the prior test period, representing an increase of approximately 8%. The primary contributing factors were changes in (1) weather driven demand, and (2) commodity prices.

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

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

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

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

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

A. DEP's current coal burn projection for the billing period is 4.4 million tons, compared to 3.6 million tons consumed during the test period. DEP'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, DEP projects average delivered coal costs of approximately $66.12 per ton for the billing period compared to $84.81 per ton in the test period. The lower projected cost is due, in part, to newly negotiated rail transportation contracts that went into effect March 1, 2019. This projected delivered cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEP is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEP's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

DEP's current natural gas burn projection for the billing period is approximately 158.5 million MMBtu, which is a decrease from the 182.4 million MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.76 per MMBtu, compared to $3.12 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

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

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

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

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

A. Yes, it does.

BY MR. JIRAK:

Q Mr. Phipps, have you prepared a summary of your testimony?

A I have.

Q Please proceed.

(WHEREUPON, the summary of BRETT PHIPPS is copied into the record as read from the witness stand.)

DUKE ENERGY PROGRESS, LLC
BRETT PHIPPS DIRECT TESTIMONY SUMMARY
DOCKET NO. E-2, SUB 1204

The purpose of my testimony is to describe DEP's fossil fuel purchasing practices, provide actual fossil fuel costs for the test period, and describe changes projected for the billing period.

DEP serves its customer by ensuring that its generating assets are reliably and economically committed and dispatched. DEP considers numerous factors such as the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving customers.

Coal markets continue to be in a state of flux due to a number of factors. With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. 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.

DEP's average delivered cost of coal per ton for the review period was $84.81 per ton, compared to $80.82 per ton in the prior review period, representing an increase of approximately 5%. This includes an average transportation cost of $32.72 per ton in the review period, compared to $29.42 per ton in the prior review period, representing an increase of approximately 11%. The Company's average cost of gas purchased for the review period was $4.05 per million MBtu, as compared to $4.68 per million MBtu in the prior review period, representing a decrease of approximately 13%. These costs include gas supply, transportation, storage and financial hedging.

DEP's coal burn for the review period was 3.6 million tons, compared to a coal burn of 3.9 million tons in the prior review period, representing a decline of approximately 7%. The Company consumed approximately 182.4 million MBtu of natural gas in the review period, compared to 169.4 million MBtu in the prior review period, representing an increase of 8%. The primary contributing factors were changes in weather driven demand and commodity prices. DEP's projections for the billing period include approximately 4.4 million tons of coal and 158.5 million MBtu of natural gas consumed. These projections are subject to change due to multiple factors such as, but not limited to, changes in commodity prices and weather driven demand.

This concludes my testimony summary.

MR. JIRAK: Chair Mitchell, the witness is available for cross examination at this time. Now, understanding that the first question is going to deal with confidential information, I guess I would begin by asking that anyone in the room here who has not executed an acknowledgment of the confidentiality agreement would please exit. I'm not necessarily --

MR. WEST: Actually, Jack, I apologize. Gudrun and I talked very briefly and I have one or two very quick questions that are public --

MR. JIRAK: Okay.

MR. WEST: -- as opposed to confidential.

MR. JIRAK: Okay.

MR. WEST: So, if it's okay, I'll begin.

CROSS EXAMINATION BY MR. WEST:

Q Mr. Phipps, in your summary you said that coal markets continue to be in a state of flux.

Please don't hurt your neck. You're welcome to look forward and talk to the Commission.

Is that a reference exclusively to the variability of price in the coal market or something else?

A It's multiple factors. In my expanded testimony there is a -- it goes into expanded areas, whether it's extended regulation; safety regulations on the industry; production cost; demand for the product; whether it be export or domestic; price is a part of that as well; and the financial health of the companies; and the recent bankruptcies that's taken place.

Q Okay. Is the aggregation of those factors leading to a -- some variability in price?

A Obviously, there's several factors. But, yes, those are part of prices that impact the market. It's a market-driven price and market demands. We go after physical solicitations where it solicits the market on a physical basis. But, yes, those are not limited to but those are some of the factors that impact price.

Q And can you tell us for approximately what period the coal market has been in a state of flux, meaning for a year, five years, a decade?

A I'm -- my observation is through -- it's been in several years.

Q Can you be a little more specific than that?

A It's pretty broad. I -- you know, I'll expand. So there has been periods of where it's very healthy. I'm going to say it's cyclical in nature. For instance, in 2008, it was a very healthy couple of years for the industry. It was a healthy export market and healthy demand. That followed by lower gas prices in 2012, it really drove the industry into some financial challenges. Now, fast forward to last year, domestically, coal is still on the decline because of low natural gas and other generation forms, but it was a healthy export market. So the export markets, from a global perspective, really benefited. Now, fast forward to today, both domestic and export demand for coal is down; therefore, that's the reason why you're seeing a continued financial challenge and all the other drivers. So I'm not trying to not answer your question, it's just cyclical in nature over time.

Q But it sounds like, based on what you said, that the cyclical nature of this flux could have started as early as 2008. Did I understand correctly?

A It actually has been -- actually it's been really through a long time for the industry, you know, even back to 2005 was a healthy timeframe for the industry which was a decline. So I would say over the last decade at least, if not more, it's been cyclical in nature for the ups and downs.

MR. WEST: I don't have any further questions. Thank you very much.

MS. THOMPSON: Okay. And I do have some questions on confidential exhibits though. Sorry, Mr. Jirak, you had started to address that.

MR. JIRAK: Right. So, again, I don't necessarily recognize every single person in the room but I believe the vast majority of the people have executed or are with Public Staff or Duke. I don't mean to call anyone out but, Gray Styers, I don't know if --

MR. STYERS: I have not.

MR. JIRAK: So I think at this point you probably need to leave the room. Again, based on my recognition here I believe everyone else is either with the Public Staff, with Duke, or has executed a Confidentiality Agreement.

(WHEREUPON, the following is confidential and shall be filed under seal.)

Q [redacted]

[redacted]

MS. THOMPSON: [redacted]

CHAIR MITCHELL: [redacted]

MS. THOMPSON: [redacted]

[redacted]

BY MS. THOMPSON:

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

Q [redacted]

[redacted]

A [redacted]

Q [redacted]

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Q [redacted]

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Q [redacted]

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[redacted]

Q [redacted]

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Q [redacted]

MR. PAGE: [redacted]

MS. THOMPSON: [redacted]

[redacted]

MR. PAGE: [redacted]

MS. THOMPSON: [redacted]

MR. JIRAK: [redacted]

MS. THOMPSON: [redacted]

CHAIR MITCHELL: [redacted]

BY MS. THOMPSON:

Q [redacted]

A [redacted]

Q [redacted]

[redacted]

MR. JIRAK: [redacted]

MS. THOMPSON: [redacted]

MR. JIRAK: [redacted]

MS. THOMPSON: [redacted]

BY MS. THOMPSON:

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

Q [redacted]

[redacted]

CHAIR MITCHELL: [redacted]

BY MS. THOMPSON:

Q [redacted]

A [redacted]

Q [redacted]

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Q [redacted]

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A [redacted]

Q [redacted]

A [redacted]

Q [redacted]

MS. THOMPSON: [redacted]

CHAIR MITCHELL: [redacted]

MR. JIRAK: [redacted]

MS. DOWNEY: [redacted]

CHAIR MITCHELL: [redacted]

(WHEREUPON, confidential session has ended.)

CHAIR MITCHELL: Any additional cross examination for Mr. Phipps?

(No response)

Redirect?

MR. JIRAK: We have no redirect.

CHAIR MITCHELL: Questions from the Commission?

(No response)

Okay. No questions from the Commission.

MR. JIRAK: Thank you.

CHAIR MITCHELL: Mr. Phipps, you are excused.

THE WITNESS: Thank you.

(The witness is excused)

MS. THOMPSON: Thank you, Madam Court Reporter. I would like to move admission of Sierra Club Confidential Phipps Cross Exam Exhibits 1, 2 and 3.

CHAIR MITCHELL: Without objection, the motion is allowed.

(WHEREUPON, Sierra Club Confidential Phipps Cross

Examination Exhibits 1, 2 and 3
are received into evidence.)

CHAIR MITCHELL: Ms. Thompson, I'd ask that you work with the court reporter to make sure that the exhibits are appropriately identified as confidential.

MS. THOMPSON: (Nods head in agreement).

CHAIR MITCHELL: Mr. Jirak, call your next witness, please.

MR. JIRAK: Thank you, Chair Mitchell. At this time DEP would like to call to the stand Dana M. Harrington.

CHAIR MITCHELL: Good afternoon, Ms. Harrington.

MS. HARRINGTON: Good afternoon.

CHAIR MITCHELL: Let's go ahead and get you sworn in.

DANA M. HARRINGTON;
having been duly sworn,
testified as follows:

DIRECT EXAMINATION BY MR. JIRAK:

Q Ms. Harrington, would you please begin by stating your full name and title for the record?

A Dana Marie Harrington, Rates Manager.

Q Ms. Harrington, did you prepare and cause to be filed in this proceeding direct testimony consisting of 15 pages of testimony, six exhibits and 16 workpapers?

A I did.

Q And did you also prepare and cause to be filed in this proceeding supplemental testimony consisting of seven pages of testimony, six exhibits and 16 workpapers?

A I did.

Q Do you have any changes to make to your direct or supplemental testimony at this time?

A I do not.

Q Ms. Harrington, if I were to ask you the same questions contained in your testimony today, would your answers remain the same?

A They would.

MR. JIRAK: Chair Mitchell, at this time I would request that the prefiled direct and supplemental testimony, and exhibits, and workpapers of Dana M. Harrington be copied into the record as if given orally from the stand.

CHAIR MITCHELL: The motion is allowed.

(WHEREUPON, Harrington Exhibits 1 - 6 and Harrington Workpapers 1 -

16b are marked for identification as prefiled.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dana M. Harrington, and my business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am a Rates Manager supporting both Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Companies").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Psychology with Honors from the University of North Carolina at Chapel Hill and I am a certified public accountant licensed in the State of North Carolina. I began my accounting career in 2005 with Greer and Walker, LLC as a tax accountant and later a staff auditor. From 2007 until 2010 I was an Accounting Analyst with Duke Energy in the Finance organization. In 2010, I joined the Rates Department as a Lead Accounting Analyst where I have spent the past eight years. I was recently promoted to the position of Rates and Regulatory Strategy Manager.

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

A. No.

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

A. Yes. Duke Energy Progress' 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 Harrington Exhibits 1 through 6, along with supporting workpapers. The test period used in supplying this information is the period of April 1, 2018 through March 31, 2019 ("test period"), and the billing period is December 1, 2019 through November 30, 2020 ("billing period").

Q. WHAT IS THE SOURCE OF THE ACTUAL INFORMATION AND DATA FOR THE TEST PERIOD?

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

Q. WERE HARRINGTON EXHIBITS 1 THROUGH 6 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes, these exhibits were prepared by me or under my supervision and consist of the following:

- Exhibit 1: Summary Comparison of Fuel and Fuel-Related Costs Factors.
- Exhibit 2, Schedule 1: Fuel and Fuel-Related Costs Factors - reflecting a 94.62% proposed nuclear capacity factor and projected billing period megawatt hour ("MWh") sales.

- Exhibit 2, Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 94.62% proposed nuclear capacity factor and normalized test period MWh sales.
- Exhibit 2, Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting an 91.8% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for comparable units and projected billing period MWh sales.
- Exhibit 3, Page 1: Calculation of the Proposed Composite Experience Modification Factor ("EMF") rate.
- Exhibit 3, Page 2: Calculation of the EMF for residential customers.
- Exhibit 3, Page 3: Calculation of the EMF for small general service customers.
- Exhibit 3, Page 4: Calculation of the EMF for medium general service customers.
- Exhibit 3, Page 5: Calculation of the EMF for large general service customers.
- Exhibit 3, Page 6: Calculation of the EMF for lighting customers.
- Exhibit 4: Normalized Test Period MWh Sales, Fuel and Fuel-Related Revenue, Fuel and Fuel-Related Expense, and System Peak.
- Exhibit 5: Nuclear Capacity Ratings.
- Exhibit 6, Report 1: March 2019 Monthly Fuel Report, as required by NCUC Rule R8-52.
- Exhibit 6, Report 2: March 2019 Monthly Base Load Power Plant Performance Report, as required by NCUC Rule R8-53.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON HARRINGTON EXHIBIT 1.

A. Harrington Exhibit 1 presents a summary of fuel and fuel-related cost factors, which include: the currently approved fuel and fuel-related cost factors, the projected fuel and fuel-related cost factors using the NERC five-year national weighted average capacity factor with projected billing period sales, the projected fuel and fuel-related cost factors using the proposed capacity factor with normalized test period sales, and the proposed fuel and fuel-related cost factors using the proposed capacity factor with projected billing period sales.

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

A. The Company proposes that the fuel and fuel-related costs factors shown in the table below be reflected in rates during the billing period. The factors that DEP proposes in this proceeding utilize a 94.62% nuclear capacity factor as testified to by Company witness Henderson. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Harrington Exhibit 1 in cents per kWh ("cents/kWh"), are:

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Proposed Fuel and Fuel-Related Costs cents/kWh	2.355	2.469	2.432	2.099	2.121
EMF Increment/(Decrement) cents/kWh	0.252	0.120	0.170	0.557	0.435
Net Fuel and Fuel-Related Costs Factors cents/kWh	2.607	2.589	2.602	2.656	2.556

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

A. If the proposed fuel and fuel-related cost factors are approved, there will be a 2.4% decrease, on average, in customers' bills. The table below shows both the proposed and existing fuel and fuel-related cost factors (excluding regulatory fee).

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Proposed Factors cents/kWh	2.607	2.589	2.602	2.656	2.556
Current Factors cents/kWh	2.886	2.919	2.820	2.795	3.136

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

A. For this filing, DEP 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 DEP's and DEC's generation resources with the joint dispatch, which optimizes the generation fleets of DEP and DEC combined.

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

A. Exhibit 2 is divided into three schedules. Schedule 1 presents the prospective fuel and fuel-related costs. The calculation uses the nuclear capacity factor of 94.62%, as explained in Company witness Henderson's testimony, and provides the projected MWh sales for the billing period on which system generation and costs are based. Schedule 2 also uses the proposed capacity factor of 94.62% but against normalized test period kWh sales, as prescribed by NCUC Rule R8-55(e)(3), which requires the use of the methodology adopted by the Commission in the Company's last general rate case.

The Capacity factor shown on Schedule 3 is prescribed in NCUC Rule R8-55(d)(1). The NERC five-year national weighted average nuclear capacity factor used here is 91.8%. This capacity factor is based on the 2013 through 2017 data reported in the NERC's Generating Unit Statistical Brochure ("NERC Brochure") for units comparable to DEP's nuclear fleet. Schedule 3 also uses the projected billing period kWh sales as required by 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 cost factors by customer class resulting from the allocation of renewable and qualifying facility capacity costs by customer class on the basis of production plant as approved in the Company's 2017 and 2018 annual fuel proceedings (Docket Nos. E-2, Sub 1146 and E-2, Sub 1173).

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 DEP's proposed fuel and fuel-related cost factors for the residential, small general service, medium general service, large general service, and lighting classes (excluding regulatory fee), using the uniform percentage average bill adjustment method.

Q. PLEASE SUMMARIZE THE METHOD USED TO ADJUST KWH GENERATION IN HARRINGTON EXHIBIT 2, SCHEDULES 2 AND 3.

A. As used in DEP's most recent general rate case, and for the purposes of this filing, Harrington Exhibit 2 Schedule 2 adjusts the coal generation produced by the dispatch model 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, DEP increased the level of coal generation produced by the dispatch model to account for the decrease in nuclear generation. The decrease in nuclear generation results from assuming an 91.8% NERC nuclear capacity factor compared to the proposed 94.62% nuclear capacity factor.

Q. HOW ARE PROJECTED FUEL AND FUEL-RELATED COSTS ALLOCATED?

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 to set fuel rates by customer class in this fuel proceeding as adopted in DEP's 2018 fuel and fuel-related cost recovery proceeding under Docket No. E-2, Sub 1173 with the exception of capacity-related purchased power costs described in subsections (5), (6) and (10) of N.C. Gen. Stat. § 62-133.2(a1), which are allocated based upon the production plant allocator from the most recent annual cost of service study.

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

A. Harrington Exhibit 2, Page 3 of Schedule 1 shows DEP's proposed fuel and fuel-related cost factors for the residential, small general service, medium general service, large general service, and lighting classes (excluding regulatory fee). The uniform bill percentage decrease of 2.4% was calculated by dividing the fuel and fuel-related cost decrease of $89 million for the North Carolina retail jurisdiction by the normalized annual North Carolina retail revenues at the existing rates of $3.7 billion. The cost decrease of $89 million 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 equals the sum of the rate necessary to recover projected billing period fuel costs and the proposed composite EMF increment as computed on Harrington Exhibit 3, Page 1. Harrington 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 COST FACTORS FOR EACH CUSTOMER CLASS DERIVED FROM THE UNIFORM PERCENT ADJUSTMENT COMPUTED ON HARRINGTON EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. On each of Harrington Exhibit 2, Page 3 of Schedules 1, 2, and 3, the equal percent decrease for each customer class is applied to current annual revenues by customer class to determine a revenue decrease for each customer class. The revenue decrease is divided by the projected billing period sales for each class to derive a cents/kWh decrease. The current total fuel and fuel-related cost factors for each class are adjusted by the proposed cents/kWh decrease to get the proposed total fuel and fuel-related cost factors. The proposed total fuel factors are then separated into the prospective and EMF components by subtracting the EMF components for each customer class as computed on Harrington Exhibit 3, Pages 2, 3, 4, 5, and 6 to derive the prospective rate component for each customer class. Presentation of the projected fuel and fuel-related cost factors and the projected EMF increments are shown on Harrington Exhibit 2, Page 2 of Schedules 1, 2, and 3.

Q. DID YOU DETERMINE THAT DEP'S ANNUAL INCREASE IN THE AGGREGATE AMOUNT OF THE COSTS IDENTIFIED IN SUBSECTIONS (4), (5), (6), (10) AND (11) OF N.C. GEN. STAT. § 62-133.2(A1) DID NOT

EXCEED 2.5% OF ITS NC RETAIL GROSS REVENUES FOR 2018, AS REQUIRED BY N.C. GEN. STAT. § 62-133.2(A2)?

A. Yes. The Company's analysis shows that the annual increase in the costs recoverable under the relevant sections of the statute did not exceed 2.5% of DEP's gross revenues for the NC retail jurisdiction for the preceding calendar year; therefore, no adjustment has been made to exclude a portion of DEP's projected costs for the billing period as shown on Harrington Exhibit 2, Page 3 of Schedules 1, 2, or 3.

Q. HARRINGTON EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD (OVER)/UNDER RECOVERY BALANCE AND THE PROPOSED EMF RATE. HOW DID ACTUAL FUEL EXPENSES COMPARE WITH FUEL REVENUE DURING THE TEST PERIOD?

A. Harrington Exhibit 3, Page 1 demonstrates that, for the test period, the Company experienced a net under-recovery of approximately $146.8 million for the combined customer classes of the North Carolina retail jurisdiction. In its 2018 fuel proceeding, Docket E-2, Sub 1173, the Company reduced its forecasted purchased power costs by $57.4 million in order to comply with limitations in annual fuel increases as prescribed in G.S. 62-133.2(a2). As a result, the Company expected fuel revenues during the test period would be lower than fuel expenses, resulting in an under-collection.

The test period (over)/under collection was determined each month by comparing the actual fuel revenues collected from each class to actual fuel and fuel-related costs incurred by class based on the actual monthly sales of each class. DEP System fuel and fuel-related costs incurred were first allocated to the North Carolina 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 of purchased power capacity costs from renewables and qualifying facilities were allocated among customer classes based on production plant allocators from DEP's cost of service study. All other fuel and fuel-related costs were allocated among customer classes using the uniform percentage average bill adjustment method consistent with DEP's previous annual fuel proceeding.

Q. IS THE COMPANY PROPOSING ANY COST ADJUSTMENTS TO THE TEST PERIOD UNDER-COLLECTION OF FUEL AND FUEL-RELATED COSTS?

A. Yes. The Company is proposing to recover a component of net gain/loss on the sale of by-products included in test period costs on a cash basis rather than an accrual basis. The recommended adjustment relates to liquidated damages on the sale of by-products that are to be paid over 10 years under a settlement agreement with a third party to whom the Company sells gypsum. For accounting purposes, the full 10-year liability was accrued in December 2018. These system costs were reflected in the monthly fuel filings as they were recorded to the Company's books in FERC account 502, which is incorporated into the computation of net gain/loss on the sale of by-products. Currently, the NC retail share of these costs is reflected in the test period under-collection balance of $146.8 million. In this case, the Company believes that it is more equitable to customers for the Company to recover these costs as the amounts are paid, rather than when the liability was accrued. To achieve this result, an adjustment of ($44.1) million, to remove the North Carolina retail portion of the total amount recorded to the books during the test year, is presented on Harrington Exhibit 3, Page 1. Subsequently, a second adjustment of $6.6 million is presented on Harrington Exhibit 3, Page 1 to recognize only the North Carolina retail portion of the cash payments made during the test period. These adjustments are further identified by customer class on Harrington Exhibit 3, Pages 2 through 6.

In addition, the North Carolina retail portion of the cash payment to be made during the billing period, which totals approximately $5 million, is included in projected costs and would be included in projected costs annually until terms of the agreement are complete.

Q. WHY ARE THESE LIQUIDATED DAMAGES PROPERLY RECOVERED IN FUEL RATES?

A. N.C. Gen. Stat. § 62-133.2(a1)(9) specifies that "cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs." In this case, the liquidated damages are properly included in the calculation of net gain/loss on the sale of by-products because the liquidated damages provision was an essential commercial term of a larger transaction that was reasonably and prudently entered into by the Company for the benefit of customers. Due to changes in coal consumption over time, the Company was not able to meet its contractual gypsum supply obligations. Nevertheless, the Company's decision to enter into the arrangement was prudent and reasonable and the transaction as a whole still provided a benefit to customers.

Q. WERE ANY OTHER COST ADJUSTMENTS MADE TO THE TEST PERIOD UNDER-COLLECTION OF FUEL AND FUEL-RELATED COSTS?

A. Yes. Included in the test period under-recovered balance is the under-collection related to the coal inventory rider established in Ordering Paragraph 12 of the

Commission's February 23, 2018 *Order Accepting Stipulation, Deciding Contested Issue and Granting Partial Rate Increase* in Docket No. E-2, Sub 1142. DEP is not recovering any coal inventory rider costs other than interest beyond the month of October 2018 when the termination requirements were met, but the rates associated with the rider were not terminated from customer billings until service on and after December 1, 2018. Additional amounts collected through January 2019 reduced the October under-collected balance. Interest has been calculated on the under-collected balance through November 30, 2019. The inclusion of the coal inventory rider under-collection is shown on Harrington Exhibit 3, Page 1, and is further identified at the customer class level on Pages 2 through 6.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON HARRINGTON EXHIBIT 4.

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Harrington Exhibit 4 presents 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, consistent with the methodology utilized in DEP's most recent general rate case (Docket No. E-2, Sub 1142) and DEP's most recent fuel and fuel-related cost recovery proceeding (Docket No. E-2, Sub 1173). Customer growth was determined using regression analysis for residential, small general service, and lighting classes, and a customer-by-customer analysis for medium and large general service customers. Finally, Harrington Exhibit 4 shows the test period peak demand for the system and for North Carolina Retail customer classes.

Q. PLEASE IDENTIFY WHAT IS SHOWN ON HARRINGTON EXHIBIT 5.

A. Harrington Exhibit 5 presents the capacity ratings for each of DEP's nuclear units, in compliance with Rule R8-55(e)(12).

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

A. Yes. As shown on Harrington Exhibit 6, DEP's test year actual fuel and fuel-related costs were 2.658 cents/kWh. Key factors in DEP's ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio of nuclear, coal, natural gas, and hydro, the capacity factors of its nuclear fleet, and fuel procurement strategies, which mitigate volatility in supply costs. Other key factors include DEP's and DEC's respective expertise in transporting, managing and blending fuels, procuring reagents, and utilizing purchasing synergies of the combined Company, as well as the joint dispatch of DEP's and DEC's generation resources.

Company witness Henderson discusses the performance of DEP's nuclear generation fleet and Company witness Repko discusses the performance of the fossil/hydro/solar fleet, as well as the chemicals that DEP uses to reduce emissions. Company witness Phipps discusses fossil fuel costs and fossil fuel procurement strategies, and Company witness Church discusses nuclear fuel costs and nuclear fuel procurement strategies.

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

A. The largest component of the decrease in the proposed fuel and fuel-related cost factors is the request for collection of approximately $109.6 million of under-collected fuel costs via the proposed EMF increment, compared to the $224.3 million of under-collected fuel costs included in the existing EMF increment.

Q. HAS THE COMPANY FILED WORKPAPERS SUPPORTING THE CALCULATIONS, ADJUSTMENTS, AND NORMALIZATIONS AS REQUIRED BY NCUC RULE R8-55(E)(11)?

A. Yes. Working papers supporting the calculations, adjustments, and normalizations utilized to derive the proposed fuel factors are included with this filing.

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

A. Yes, it does.

(15 PAGES)

(WHEREUPON, Revised Harrington Exhibit 1; Revised Harrington Exhibit 2, Schedule 1, page 3 of 3, Schedule 2, pages 1 - 3, and Schedule 3, page 3 of 3; Revised Harrington Exhibit 3 and 4; Revised Harrington Workpapers 8a, 9, 15, 16, 16a and 16b are marked for identification as prefiled.)

(WHEREUPON, the prefiled supplemental of DANA M. HARRINGTON is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**SUPPLEMENTAL TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF DANA M. HARRINGTON FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dana M. Harrington and my business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes, on June 11, 2019, I caused to be pre-filed with the Commission my direct testimony, six exhibits, and sixteen supporting workpapers.

Q. YOUR SUPPLEMENTAL TESTIMONY INCLUDES FOUR REVISED EXHIBITS AND FOUR 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:

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

- Revised Exhibit 2, Schedule 1, Page 3: Fuel and Fuel-Related Costs Factors - reflecting a 94.62% proposed nuclear capacity factor and projected billing period megawatt hour ("MWh") sales; Schedule 2, Pages 1, 2, & 3: Fuel and Fuel-Related Costs Factors - reflecting a 94.62% proposed nuclear capacity factor and normalized test period MWh sales; and Schedule 3, Page 3: Fuel and Fuel-Related Costs Factors - reflecting an 91.8% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for comparable units and projected billing period MWh sales.

- Revised 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 small general service customers; Page 4: Calculation of the EMF for medium general service customers; Page 5: Calculation of the EMF for large general service customers, and Page 6: Calculation of the EMF for lighting customers.
- Revised Exhibit 4: Normalized Test Period MWh Sales, Fuel and Fuel-Related Revenue, Fuel and Fuel-Related Expense, and System Peak.
- Revised Workpaper 8a: Calculation of Allocation percentages based on Normalized Test Period Sales.
- Revised Workpaper 9: Customer Growth Adjustment.
- Revised Workpaper 15: Scenario Differences.
- Revised Workpaper 16: 2.5% Calculation Test; Workpaper 16a: 2.5% Calculation Test – Normalized, and Workpaper 16b: 2.5% Calculation Test – Detail Calculation.

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

A. The purpose of my testimony is to present the revised rates reflecting the impacts related to three updates in my direct exhibits and workpapers.

The primary update relates to the proposed EMF increment for the under-recovery of fuel and fuel-related costs. NCUC Rule R8-55(d)(3) allows the Company to update the fuel and fuel-related cost recovery balance up to thirty (30) days prior to the hearing. The Company elects this option and supplements the direct testimony and exhibits to include the fuel and fuel-related cost recovery balance as of the 15 months ended June 30, 2019. The Company experienced an under-collection of $41,484,352 during the months April through June 2019. As shown on Revised Harrington Exhibit 3, the incorporation of the updated test period under-collection balance resulted in an under-recovered balance as of June 30, 2019 of $151,035,306 (following adjustments).

In addition, I update proposed rates to reflect revisions to the customer class allocation of manual adjustments made to the EMF under collection balance.

Finally, I update rates presented for informational purposes to reflect revisions to the customer growth component of normalized test period sales.

Q PLEASE IDENTIFY THE SPECIFIC SCHEDULES REVISED FOR EACH UPDATE.

A. The primary update, to incorporate the EMF under collection balance at June 30, 2019, impacts the following exhibits:

- Exhibit 1,
- Exhibit 2, Schedules, 1, 2, and 3, Page 3, and
- Exhibit 3, Pages 1-6.

The second update, to restate the customer class allocations of the manual adjustments to the EMF as seen on Exhibit 3, Page 1, impacts the following exhibits:

- Exhibit 1 and
- Exhibit 3, Pages 2-6.

The third update, to revise the Customer Growth adjustment used in the calculation of normalized test period sales, impacts the following exhibits:

- Exhibit 1,
- Exhibit 2, Schedule 2, Pages 1 and 2, and
- Exhibit 3, Pages 1-6.

Q. PLEASE EXPLAIN THE REASON FOR UPDATING THE CUSTOMER CLASS ALLOCATIONS OF THE MANUAL ADJUSTMENTS TO THE EMF.

A. While updating the proposed EMF to a 15-month ending balance, the Company reevaluated the allocation method used to assign the customer classes their portions of the manual adjustments. In my initial direct testimony, each class's total test period sales as a percentage of NC retail total test period sales had been used to assign the customer classes their portions of the adjustments. Since the intent was to adjust the customer classes respective to their contributions to the total under-collected EMF balance, the Company decided to update the allocations to the customer classes according to each class's share of NC retail sales in the months the costs were recorded to the general ledger and included in the over/under collection computation. The impact of this correction to proposed customer rates is as follows: residential (0.015) cents per kWh, small general service 0.019 cents per kWh, medium general service 0.016 cents per kWh, large general service 0.002 cents per kWh, and lighting (0.010) cents per kWh.

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

A. The Public Staff recommended adjustments to the customer growth calculation, which the Company agrees were necessary, resulting in a change of (2,062) MWh to adjusted

NC system sales. This further equates to adjustments of (2,024) MWh to NC retail sales, (1) MWh to SC retail sales, and (38) MWh to wholesale sales. The fuel rates proposed by the Company are not affected by this update. This revision only affects the rate for Small General Service customers presented for informational purposes on Exhibit 1, line 6. The informational rates on Exhibit 1 line 6 are supported by Exhibit 2, Schedule 2, which presents a scenario using the proposed nuclear capacity factor of 94.62% with normalized test period sales.

Q. WHAT IS THE RATE IMPACT OF THESE UPDATES?

A. The NC Retail Total Fuel Costs were increased by $ 41,900,604 from the amounts filed in my direct testimony Exhibit 2, Schedule 1, page 3. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Revised Harrington Exhibit 1, are as follows:

Description	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Total adjusted Fuel and Fuel-Related Costs cents/kWh	2.344	2.527	2.468	2.056	2.281
EMF Increment/(Decrement) cents/kWh	0.394	0.217	0.236	0.666	0.548
Net Proposed Fuel and Fuel-Related Costs Factors cents/kWh	2.738	2.744	2.704	2.722	2.829

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

A. The revised proposed fuel and fuel-related costs factors will result in a 1.3% decrease, on average, in customers' bills. The rates previously proposed in my direct testimony would result in a 2.4% decrease, on average, in customers' bills.

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

A. Yes, it does.

BY MR. JIRAK:

Q Ms. Harrington, have you prepared a summary of your testimony?

A I have.

Q Please proceed.

A Good afternoon, Commissioners.

(WHEREUPON, the summary of DANA M. HARRINGTON is copied into the record as read from the witness stand.)

DUKE ENERGY PROGRESS, LLC
DANA M. HARRINGTON DIRECT and SUPPLEMENTAL DIRECT
TESTIMONY SUMMARY
DOCKET NO. E-2, SUB 1204

The purpose of my direct testimony is to describe fuel factors by customer class to become effective December 1, 2019 for DEP's North Carolina retail customers. My testimony reports DEP's Experience Modification Factor ("EMF"), for fuel and fuel-related costs, including purchased power capacity costs from renewable and qualifying facility sources, incurred while providing energy service to North Carolina customers for the test period of April 1, 2018 through March 31, 2019. In addition, my testimony provides DEP's projected fuel and fuel-related costs, including purchased power capacity costs from renewables and qualifying facility sources, for the billing period of December 1, 2019 through November 30, 2020.

One item of note from my testimony is the proposal to recover liquidated damages on the sale of by-products on a cash basis rather than an accrual basis. Based on this adjustment, the Company is requesting cost recovery of North Carolina's retail share of cash payments within the EMF balance, which is $6.6 million. Also included in this filing is the request for approximately $5 million dollars in future cash payments anticipated in the projected billing period. The liquidated damages are properly recoverable through fuel rates, as the Company has experienced a net loss resulting from its sales of gypsum produced in the generation of electricity. Finally, the EMF balance proposed in my exhibits also includes approximately $250,000 of an under-recovered balance related to the coal inventory rider which expired November 30, 2018.

The purpose of my supplemental direct testimony is to update the proposed EMF to incorporate the under-recovered fuel and fuel-related costs experienced during the period of April 1, 2019 – June 30, 2019. Following the incorporation of the update period, the North Carolina retail under-recovered balance as of June 30, 2019 is approximately $151 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 revised the customer class allocation of the manual adjustments to the EMF balance and revised the customer growth component of normalized test period sales for informational purposes.

The net proposed fuel and fuel-related costs factors by customer class are: 2.738 cents per kWh for Residential customers, 2.744 cents per kWh for Small General Service customers, 2.704 cents per kWh for Medium General Service customers, 2.722 cents per kWh for Large General Service customers, and 2.829 cents per kWh for Lighting customers. These rates are a decrease from prior year rates for all customer classes.

The Company's test period fuel costs reflect DEP's continuing efforts to maintain reliable service in an efficient manner, thereby minimizing the total cost of providing service to DEP's North Carolina retail customers. The impact of the rates set forth in my testimony, is a decrease of 1.3% for all customer classes.

This concludes the summary of my testimony.

MR. JIRAK: Thank you, Ms. Harrington.

Chair Mitchell, the witness is available for cross examination.

CROSS EXAMINATION BY MR. WEST:

Q Good afternoon, Ms. Harrington, how are you?

A Good. How are you?

Q Because we're getting close to the five o'clock hour and I don't want to carry these documents again, I'm going to go ahead and pass out four fairly bulky exhibits and have them marked.

(Mr. West handed out exhibits.)

A Thank you.

MR. WEST: I'm going to ask that the four exhibits be marked -- the first one marked as FPWC Harrington Confidential Cross Examination Exhibit 1.

MR. JIRAK: Just to pause you one second, you said the first one --

MR. WEST: It would be -- it was a -- it's a confidential document that starts with the word "second".

MR. JIRAK: Okay.

MR. WEST: They should all be in order.

The second document which is a discovery request and response also marked confidential would --

I would ask to be marked as FPWC Harrington Confidential Cross Examination Exhibit 2. The third exhibit is an opinion and final judgment. It's a public document. So I would ask that it be marked as FPWC Harrington Cross Examination Exhibit 3. And the fourth document is labeled Confidential Settlement and I would ask that it be labeled as FPWC Harrington Confidential Cross Examination Exhibit 4.

So let's --

MR. JIRAK: Pardon. Sorry to keep interrupting but if we're gonna -- if the questions are now going to touch on the substance of the confidential documents then we'll have to once again ask - apologies to Mr. Styers - Mr. Styers to leave the room again. But I guess you can let us know --

MR. WEST: Not yet.

MR. JIRAK: Okay.

MR. WEST: I'll try to pause and let you know if I'm going to ask about substance. I'm going to ask her to identify them. I assume the titles are not confidential. I just want to know whether she recognizes them and has seen them before. But I'm not going to ask about substance at this point.

MR. JIRAK: Let me check on one question.

If you're going to reference the titles, I need to confirm one thing with my team before you publicly disclose the title of one of the documents.

MR. WEST: Which?

MR. JIRAK: It would be your Exhibit Number 4.

MR. WEST: Is it okay if we confer?

(Conversation among counsel.)

MR. JIRAK: Please proceed with your questions. I have confirmed that the titles of the four documents are fine to publicly discuss.

MR. WEST: Thank you very much.

BY MR. WEST:

Q So, Ms. Harrington, in preparing your testimony about the liquidated damages, did you have an opportunity to review the --

A All of these --

Q -- document marked as Exhibit 1 which is entitled Second Amended and Restated Supply Agreement?

A This one I have not read as detailed as I read the initial agreement from 2004, which I noted. So I, to the degree -- no, I would not say I have read this one front to back as I have done the 2004.

Q Do you --
A This is suppose --
Q Do you recognize the document? That's all I'm asking.
A Yes. Yes.
Q Okay. And this isn't -- if you would just take a minute to look through it.
A Sure.
Q This is, in fact, the Second Amended and Restated Supply Agreement.
A Okay.
Q Correct?
A It appears to be. Yes.
Q And this agreement is the agreement that is relevant to the dispute that led to the liquidated damages, correct?
A I would consider any historical document signed with the counter-party to be relevant to the liquidated damages.
Q Okay. Do you know what an Amended and Restated Agreement is?
A It's a new contract. Yes.
Q Right.
A Well, amended -- I do -- I do, but -- continue.

Sorry.
Q So to the extent that a dispute arose after 2012, this would be the agreement the parties were operating under that was the subject of that dispute, correct?
A Probably at that time, yes.
Q So let me ask you to look at the exhibit marked number 2.
A This one? Opinion?
Q No. This is the one that says confidential in the middle and it's a discovery request. It's two pages in length.
A Oh, this one. Okay.
Q Discovery request and response. So have you seen that before?
A Yes, I have seen this.
Q And have you had an opportunity to review it?
A Yes, I have.
Q And is it -- is this a full and accurate recitation of the discovery request from the Public Staff --
A Yes.
Q -- and DEP's response?
A Yes.

Q And the third exhibit which is entitled Opinion and Final Judgment.
A Yes.
Q Have you seen that?
A I've never seen this.
Q Never seen it.
A Uh-uh (no).
Q Do you know what it is?
A Yes, I do but I've relied on the Settlement Agreement for my own study. So I have not seen this.
Q Is this relevant to the Settlement Agreement to your knowledge?
A I'm sure it's relevant, yes, but I'm not a legal person. I'm an accountant. So this didn't pertain to my testimony. This wasn't relevant to the development of my testimony.
Q Okay. And then the fourth exhibit --
A This one.
Q -- which is labeled Confidential Settlement Termination and Release Agreement.
A Yes.
Q Have you had an opportunity to --
A Yes. This is the Settlement Agreement.

Q So you recognize --
A Yes.
Q -- that document?
A Yes, I do. Yes.
Q So when you talk about any kind of settlement in your testimony, this is the settlement to which you are referring, correct?
A I trust it is unless something looks identical to this. Yes.
Q Would you mind just taking a quick look through it --
A Sure.
Q -- to make sure that there's nothing in this --
A Sure.

MR. JIRAK: I'll -- we'll accept that this is the settlement, subject to check. Ms. Harrington has no ability to look at a 40-page document and confirm it's the actual Settlement Agreement.

CHAIR MITCHELL: All right, Mr. West, I'm going to stop you right there. We're going to end for the day today.

But before we go off the record, a couple of things, because this proceeding is going to last longer than we anticipated, unless I hear an objection from any of the parties, we're -- Commissioner Brown-Bland who has a conflict tomorrow will participate in this proceeding by reading the record.

We will be back in the hearing room tomorrow at 9:00 o'clock to begin. Thank you. We are adjourned.

(The proceedings were adjourned, and will resume at 9:00 a.m. on Tuesday, September 10, 2019)

C E R T I F I C A T E

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

Kim T. Mitchell
____

Kim T. Mitchell
Court Reporter

(Per Commission Order Granting Motion to Receive Testimony into Evidence and Amend Transcript dated November 21, 2019, the rebuttal testimony of KELVIN HENDERSON is copied into the record as if given orally from the witness stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of	)	
	)	
Application of Duke Energy Progress, LLC Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities	)))))	**REBUTTAL TESTIMONY OF KELVIN HENDERSON FOR DUKE ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation with direct executive accountability for Duke Energy's North Carolina nuclear stations, including Duke Energy Progress, LLC's ("DEP" or the "Company") Brunswick Nuclear Station ("Brunswick") in Brunswick County, North Carolina, the Harris Nuclear Station ("Harris") in Wake County, North Carolina, and Duke Energy Carolinas, LLC's ("DEC") McGuire Nuclear Station, located in Mecklenburg County, North Carolina.

Q. DID YOU OFFER DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I pre-filed direct testimony in this case. My qualifications, professional experience, and current responsibilities are described in that testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to the testimony of Public Staff witness Dustin R. Metz.

Q. PLEASE SUMMARIZE YOUR TESTIMONY

A. The Company made prudent and reasonable decisions in implementing the complex Robinson Transmission Upgrade Project (the "TUP"), including managing an engineering firm that was ultimately unable to deliver on its contractual obligations. Having effectively mitigated such issue and taken substantial steps to ensure design completion and other detailed preparatory actions, the Company was fully prepared to implement the TUP at the start of the fall 2018 refueling outage. The cause of the 28-day outage extension was a shortage in qualified, electrical workers that was exacerbated by circumstances outside of the Company's control—namely, the impacts of two hurricanes.

Though Public Staff witness Dustin Metz has not identified any alleged imprudence that caused the outage extension, witness Metz has raised concerns regarding the amount of documentation produced by the Company regarding its management of the TUP over its seven-year design, planning and implementation and identified the fact that this issue also has base rate case implications. The Company has produced a significant amount of information, but to the extent that additional information can be produced that will address the base rate impacts of the TUP, the Company will endeavor to do so in the context of the next base rate case. However, as it relates to this proceeding, questions regarding the Company's management of the TUP are not relevant in light of the clear evidence that labor shortages were the cause of the extended outage.

Furthermore, whether different management decisions could have resulted in an opportunity to implement the TUP in an earlier refueling outage is an irrelevant exercise in speculation. Instead, the question for this proceeding is whether the Company was reasonably prepared at the start of the fall 2018 refueling outage to implement the project and no party to this proceeding has challenged the Company's position that it was, in fact, fully prepared to do so. This issue is ripe for decision and the evidence demonstrates that it was circumstances outside of the Company's control and not any imprudent action or decision that caused the extended outage.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PURPOSE AND BENEFIT OF THE TUP.

A. The Robinson Plant was initially placed in service in 1971. The Robinson TUP was necessary to provide regulatory and safety enhancements, as well as reliability enhancements. The TUP provides the facility with a second off-site power path, aligning the station with the current standards in the U.S. for nuclear power plants.

Significant activities associated with the TUP included replacement of the 115 KV startup transformer, the addition of a second 230 KV startup transformer and upgrades to the KV bus and transmission lines. This was an extensive, multi-year project that included complex engineering, design, construction and financial considerations.

The Robinson TUP was completed in 2018 and the majority of capital expenditures specific to this project are not yet included in rate base. In the Company's next general rate case, the Company will seek cost recovery of such costs, and the reasonableness and prudence of the project and its capital costs will be evaluated in that proceeding.

Q. WHAT RELEVANCE DOES THE ROBINSON TUP OUTAGE HAVE TO THIS PROCEEDING?

A. The only relevance to this proceeding is whether the 28-day extension of the Robinson outage occurring in the test period was a result of any imprudence on the part of the Company in connection with the TUP.

The TUP commenced in 2011 and the Company did have challenges with the early stages of the TUP, largely associated with the initial Engineer of Choice's ("EOC") inability to successfully design the project, particularly as the scope of the project became more complex. The Company ultimately determined that the initial design contract should be terminated and the initial EOC replaced. The Company sought bids and awarded the design contract to another EOC in 2015, more than three years prior to the start of the fall 2018 refueling outage.

At the start of the 2018 refueling outage, when the final phase of the TUP was scheduled to be completed, the Company was confident that the project design challenges had been resolved, and that the TUP and other projects and work scheduled during the 2018 refueling outage could be completed within the schedule allocation.

Q. DID THE CHANGE IN THE ENGINEER OR THE COMPANY'S CONTRACT OVERSIGHT OF THE TUP CAUSE THE EXTENSION OF THE 2018 OUTAGE?

A. No, it did not.

Q. WHAT WAS THE CAUSE OF THE 28-DAY EXTENSION OF THE OUTAGE?

A. The cause of the 28-day outage extension was a shortage of qualified technical contractors, a situation regarding which the Company was aware of prior to the outage but which was exacerbated by the impact of Hurricanes Florence and Michael. The refueling outage was originally scheduled to begin on September 15, 2018, just one day after Hurricane Florence made landfall. The outage was delayed for one week and on September 22, 2018, the plant entered the fall refueling outage. In the end, the Company was able to obtain only approximately 50% of the needed electricians for the project.

Q. WHAT EFFORTS DID THE COMPANY UNDERTAKE TO OBTAIN THE REQUIRED NUMBER OF RESOURCES FOR THE PROJECT?

A. Prior to the scheduled outage start date, the Company was aware that challenges existed in obtaining qualified specialty electrical supplemental workers to support the final phase of the TUP in the fall 2018 refueling outage, and therefore, the Company undertook substantial efforts to address the shortage. Specifically, the Company initiated weekly calls with the primary resource vendor to ensure that all actions to close the resource gap were underway. The primary resource vendor, a major supplemental labor provider to the nuclear industry and a vendor with a successful long-standing relationship with DEP, exerted substantial efforts to obtain additional qualified electrical workers. Supplementing the efforts of the primary resource provider, the Company independently contacted fifteen additional sub-tier vendors in an effort to secure additional electrical workers. Finally, the Company reviewed non-critical electric projects underway or scheduled during the fall of 2018 to determine if those projects could be delayed, thereby freeing additional resources to assist on the Robinson TUP. In cases where delay was acceptable, those projects were delayed and resources were redirected to the Robinson effort. In summary, the Company anticipated the labor shortage and took substantial steps to procure the necessary qualified electrical workers.

Q. GIVEN THE KNOWN RESOURCE CHALLENGES, WHY DID THE COMPANY NOT FURTHER DELAY THE ROBINSON REFUELING OUTAGE UNTIL THE DESIRED RESOURCES WERE AVAILABLE?

A. Once again, at the start of the refueling outage, the Company was confident, even with the known resource challenges, that the outage would be successfully completed within the scheduled allocation.

However, it is also important to note that the unit had reached the period where refueling was required, and any additional delays would have required the unit to operate at increasingly reduced power, and would have impacted other scheduled unit outages and the ability of the Company to efficiently meet load demands. There was simply no practical way to further delay the refueling outage beyond the one-week delay implemented based on the pending arrival of Hurricane Florence.

Q. AT THE TIME THAT THE DECISION WAS MADE TO COMMENCE WITH THE REFUELING OUTAGE, WAS THERE ANY WAY THAT THE COMPANY COULD HAVE ANTICIPATED THE WIDESPREAD FLOODING THAT WOULD FURTHER EXACERBATE THE LABOR SHORTAGE?

A. No. Once again, putting aside the fact that there was no practical way to further delay the outage, the Company could not have anticipated the wide-spread regional flooding that would result from the hurricanes, which only further constrained available labor resources, as some of the already limited available resources had to leave work and respond to emergency situations. For instance, in some cases, qualified contractors left Robinson to tend to homes damaged by flooding and in other cases, qualified contractors were prevented from traveling to Robinson due to the flooding. Finally, in some cases, qualified contractors elected to pursue more lucrative storm restoration work.

Q. DOES WITNESS METZ ACKNOWLEDGE THAT WEATHER WAS A MAJOR CAUSE OF THE EXTENDED OUTAGE?

A. Yes. The Company discussed both the resource and weather impacts on the outage and the project in significant detail with witness Metz and other members of the Public Staff and witness Metz acknowledged the impact of the weather events in his testimony.

Q. WHAT IS YOUR UNDERSTANDING OF WITNESS METZ'S VIEW ON THE RELATIONSHIP BETWEEN THE COMPANY'S MANAGEMENT OF THE TUP AND THE EXTENDED OUTAGE OCCURRING IN THE TEST PERIOD.

A. Witness Metz states that "there is significant doubt, in my professional opinion, as to whether the Company's management of the project should have resulted in it being shifted from the Spring 2017 refueling outage to the Fall 2018 refueling outage." My understanding is that witness Metz is identifying this particular decision to shift the TUP to the fall 2018 refueling outage as a potential cause of the extended outage, but witness Metz does not provide any further explanation regarding such alleged causal connection. As I explain below, the implementation delay from the spring of 2017 to the fall of 2018, had no direct impact on the extension of the 2018 refueling outage.

Q. WHAT WAS THE REASON THAT WORK SHIFTED FROM THE SPRING 2017 REFUELING OUTAGE TO THE FALL 2018 REFUELING OUTAGE?

A. As the pre-outage project milestones approached prior to the 2017 refueling outage, the Company determined that the final phase of the project was not in a ready state to support execution during the 2017 refueling outage. Therefore, the decision was made to shift the final phase of the project to the 2018 refueling outage.

Q. DO YOU STAND BEHIND THE DECISION TO SHIFT THE COMPLETION OF THE TUP TO THE 2018 REFUELING OUTAGE?

A. Yes. In my opinion the delay was the prudent decision and avoided challenges that may have arisen due to the project not being in a ready state, including open engineering issues and material procurement issues. The outage planning process is a very detailed and structured process and the deferral decision was based on wholistic consideration of the various factors that would impact the ability of the Company to execute the TUP in a timely manner.

Q. DID SHIFTING THE TUP TO THE 2018 REFUELING OUTAGE IMPACT CUSTOMERS?

A. No. Once again, I believe that the decision to shift the work from the 2017 refueling outage was well-justified based on the state of the project. The only real difference in performing the work in the fall 2018 refueling outage was the impact of both Hurricane Florence and Hurricane Michael, which was obviously completely unforeseeable at the time the decision was made.

Q. PLEASE PROVIDE AN OVERVIEW OF THE INFORMATION PROVIDED TO PUBLIC STAFF REGARDING THE ROBINSON TUP

A. In addition to the on-site meeting, the Company responded to 31 detailed data requests and provided thousands of pages of responsive documents. These documents included detailed project timelines, business analysis documents and details regarding the RFP process used to select the contractor. The responses also included the underlying contract and all amendments, annual estimated and actual project spend, project oversight guidelines and monthly hours charged by employees. Additionally, the Public Staff received a detailed list of engineering change milestones, monthly project status review reports and associated nonconformance investigations related to those monthly reviews. The information produced to Public Staff provides a very clear and detailed picture of the Company's oversight of the TUP. For instance, the project status review reports contain an immense amount of detail regarding TUP implementation that was provided to management on a monthly basis, including budget projections and variances, status of key milestones and deliverables, project risk and contingency analysis and safety performance details.

Q. PLEASE RESPOND TO WITNESS METZ ALLEGATIONS THAT "THE COMPANY'S LACK OF DOCUMENT ACCESS OR RETENTION RESTRICTED THE PUBLIC STAFF'S ABILITY TO REVIEW AND EVALUATE THE PRUDENCY OF PROJECT MANAGEMENT."

A. We believe that witness Metz has been provided sufficient documentation to assess the prudence of project management and he has certainly been provided sufficient documentation to assess the causes of the extended outage that is relevant to this case.

Q. WITNESS METZ SPECIFICALLY ALLEGES THAT THE COMPANY DID NOT FULLY COMPLY WITH COMMISSION RULE R8-28. ARE YOU FAMILIAR WITH THAT RULE?

A. I have been advised by Company counsel that the rule requires that records be maintained in accordance with a particular National Association of Regulatory

Commissioners' ("NARUC") publication entitled "Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities." ("NARUC Document Retention Policy") unless otherwise required by the Commission. While I am not directly responsible in my role for establishing internal document retention policies, I have been provided a copy of the NARUC Document Retention Policy.

Q. WHAT HAVE YOU ADVISED REGARDING THE NARUC DOCUMENT RETENTION POLICY?

A. I have been advised by counsel that the NARUC Document Retention Policy is a 32-page document that begins with some introduction and limited initial guidelines and then, starting on Page 4, provides a detailed table identifying particular documents and the corresponding minimum retention period.

Q. HAS WITNESS METZ IDENTIFIED ANY WAY IN WHICH THE COMPANY'S DOCUMENT RETENTION POLICIES DO NOT COMPLY WITH THOSE PARTICULAR DOCUMENT RETENTION POLICIES?

A. No. Witness Metz has not identified any ways in which the Company's document retention policies do not comply with those particular document retention policies. However, in a footnote, witness Metz appears to reference (though a specific cite is not provided) to some very general guidance in Section K of the NARUC Document Retention Policy that states as follows: "[n]otwithstanding the minimum retention periods provided in these regulations, if a public, utility or licensee wants to reflect costs in a current, future, or pending rate case, or if a public utility or licensee has abandoned or retired a plant subsequent to the test period of the utility's rate case, ***the utility shall retain the appropriate records to support the costs and adjustments proposed in the current or next rate case.***" (emphasis added).

Q. PLEASE COMMENT ON THIS STANDARD.

A. I am not an attorney nor am I directly responsible for establishing the Company's document retention policies. However, putting aside the issue of whether or not this particular standard is intended to be applied to fuel cost recovery proceedings (as opposed to a base rate case), the standard is inherently subjective, requiring the retention of "appropriate records to support the costs and adjustments." In short, Public Staff has not identified a concrete, objective document retention policy that the Company has violated but instead has reached a subjective determination. In this case, Company believes that it has provided records sufficient to support the costs.

Q. PLEASE PROVIDE A SPECIFIC EXAMPLE.

A. Witness Metz is critical of the volume of informal communications that the Company was able to produce regarding the project. Yet, there is nothing in the NARUC Document Retention Policy that directs that the Company must retain all email communications regarding a capital project.

Q. PLEASE COMMENT ON THE EXTENT OF PUBLIC STAFF'S DISCOVERY IN THIS CASE.

A. The vast majority of issues explored through Public Staff discovery related to the TUP are more directly related to the prudence of the capital costs and are not related to this proceeding. Frankly, the scope of the base case-related discovery conducted by the Public Staff in this proceeding was unusual for a fuel related proceeding, which made it very difficult to respond to issues that usually arise only in the context of a base rate proceeding. Nonetheless, the Company devoted considerable efforts under short discovery deadlines to provide Public Staff as much information as possible, including arranging for an on-site visit with senior management. The Company believes that it has provided sufficient information to demonstrate the reasonableness and prudence of the Company's actions as it relates to the issues in this proceeding. In addition, we also believe that these efforts will potentially enable the Company to more efficiently provide information to Public Staff in the context of the next base rate case where this issue is more directly relevant.

Q. DOES WITNESS METZ MAKE AN ADJUSTMENT IN THIS PROCEEDING TO PURCHASE POWER COSTS AS A RESULT OF THE OUTAGE EXTENSION?

A. No, he does not. Witness Metz stated that he could not conclude that it is appropriate to disallow recovery of the replacement power costs for an outage that was impacted by severe weather events.

Q. HAS THE COMPANY PROVIDED SUFFICIENT INFORMATION TO DEMONSTRATE THAT 28-DAY OUTAGE EXTENSION WAS NOT THE RESULT OF IMPRUDENCE ON THE PART OF THE COMPANY?

A. Yes, we have and the Company believes that such information demonstrates the prudence of the Company's actions.

Q. TURNING NOW TO WITNESS METZ'S OTHER RECOMMENDATIONS: PLEASE RESPOND TO WITNESS METZ'S POSITION REGARDING THE HARRIS AND ROBINSON CAPACITY FACTORS.

A. Witness Metz asserts that "when calculating the annual (test year) [capacity factor], the additional 32 MWs of station capacity should have been included, beginning when the outage was completed." For the purposes of comparing test period capacity factor results to R8-55(k) guidelines, the Company understands, but does not agree with the argument witness Metz makes regarding the timing of the restatement of the Harris maximum dependable capacity ("MDC"). The Company's timing of official MDC adjustments at the beginning of a calendar year complies with industry norms and is driven to some extent by regulatory reporting requirements. Based both on regulatory reporting requirements, and the business need for the Company to establish and maintain valid MDC ratings, the Company follows procedural guidelines in establishing and reporting MDC values. The Company's procedure requires that inlet water temperatures are normalized over a five-year period. This normalization ensures that extreme weather conditions, including abnormally high temperatures and drought conditions are appropriately considered. In many cases, engineering analysis can reasonably project a unit's MDC value, but observation over the most restrictive summer period, is necessary to establish an accurate MDC rating. Therefore, restating the Harris MDC effective January 1, 2019 was appropriate and in accordance with Company procedures. However, the Company has no objection to also providing the Public Staff with an adjusted capacity factor calculation on those occasions when the rating change is substantial, but delayed to allow for seasonal observations, and when the MDC value has been formally established and is known with certainty. However, due to regulatory reporting requirements for unit ratings to both the Nuclear Regulatory Commission and the Southeastern Reliability Council, the Company will continue to follow established procedures related to official unit ratings, including MDC.

Witness Metz also highlights in his testimony that the Robinson station exceeded a 100% capacity factor for several months during the test period. The Company acknowledges this fact, but challenges the assumption or implication that the Robinson station's MDC value is incorrect. The NRC defines MDC as "[t]he maximum amount of electricity that the main generating unit of a nuclear power reactor can reliably produce during the summer or winter (usually summer, but whichever represents the most restrictive seasonal conditions, with the least electrical output)." By definition, a unit's capacity factor can exceed

100% during any time period when inlet water temperatures are below the highest value. The fact that the Robinson station achieved a capacity factor just slightly above 100% during certain summer months does not indicate that the unit's MDC value is incorrect.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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, as amended, are a true and correct transcription to the best of my ability.

Kim T. Mitchell
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Kim T. Mitchell
Court Reporter II