PLACE: Dobbs Building, Raleigh, North Carolina

DATE: June 4, 2013

DOCKET NO.: E-7, Sub 1033

TIME IN SESSION: 9:30 A.M. TO 10:09 A.M.

BEFORE: Chairman Edward S. Finley, Jr., Presiding

Commissioner William T. Culpepper, III

Commissioner Bryan E. Beatty

Commissioner ToNola D. Brown-Bland

Commissioner Lucy T. Allen

IN THE MATTER OF:

Duke Energy Carolinas, LLC.

Application of Duke Energy Carolinas, LLC

Pursuant to G.S. 62-133.2 and NCUC Rule R8-55

Relating to Fuel and Fuel-Related Charge

Adjustments for Electric Utilities.

VOLUME 1

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

EXHIBITS

P R O C E E D I N G S

CHAIRMAN FINLEY: Let's come to order, please. Good morning. My name is Edward Finley. With me this morning are Commissioners William T. Culpepper, III, Bryan E. Beatty, ToNola D. Brown-Bland and Lucy T. Allen.

I now call for hearing Docket No. E-7, Sub 1033, which is the Application of Duke Energy Carolinas, LLC, Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities.

On March 6, 2013, Duke Filed an Application to Adjust the Fuel and Fuel-Related Cost Component for Electric Rates and the testimony and exhibits of Kim H. Smith, Sasha J. Weintraub, Joseph A. Miller, Robert J. Duncan and David C. Culp.

On March 13, 2013, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony and Establishing Discovery Guidelines and Requiring Public Notice.

On March 25, 2013, the Carolina Industrial Group for Fair Utility Rates, CIGFUR III, filed a Petition to Intervene which was granted by Commission Order dated April 1, 2013.

On March 26, 2013, the North Carolina

Sustainable Energy Association filed a Petition to Intervene which was granted by Commission Order on April 1, 2013.

On April 3, 2013, the Carolina Utility Customers Association filed a Petition to Intervene which was granted by Commission Order of April 4, 2013.

On April 13, 2013, the North Carolina Waste Awareness and Reduction Network filed a Petition to Intervene which was granted by Commission Order of April 18, 2013.

There have been a few Motions for Extensions of Time to File Testimony which have been granted.

On May 31, 2013, Duke filed a motion requesting two witnesses, Joseph A. Miller, Jr. and David C. Culp, be excused from attending the hearing. This motion was granted by Commission Order issued June 3, 2013.

On June 3, 2013, Duke filed the supplemental testimony of Robert J. Duncan.

On June 3, 2013, the Public Staff filed the testimonies and exhibits of Kennie D. Ellis, James G. Hoard and Randy T. Edwards.

Also on June 3, 2013, Duke and the Public Staff filed a Joint Agreement and Stipulation of Settlement.

That brings us up to the hearing that's before us today. In compliance with the State Ethics Act, I remind all members of the Commission to avoid conflicts of interest, and inquire whether any member of the Commission has a known conflict of interest with regard to the matters coming before us this morning.

(No response.)

CHAIRMAN FINLEY: There appear to be no conflicts, so we'll proceed. I'll now call upon the parties to announce their appearances, beginning with the Applicant.

MR. KAYLOR: Thank you, Mr. Chairman, members of the Commission. Robert Kaylor appearing on behalf of Duke Energy Carolinas.

MR. FRANKLIN: Thank you, Mr. Chairman, members of the Commission. Brian Franklin appearing on behalf of Duke Energy Carolinas.

MR. YOUTH: Good morning. Michael Youth appearing on behalf of the North Carolina Sustainable Energy Association.

MR. RUNKLE: Good morning. John Runkle representing NC WARN.

MS. DOWNEY: Dianna Downey representing the Public Staff. I represent the Using and Consuming Public.

CHAIRMAN FINLEY: Very well. Are there matters that we need to discuss before we begin with the testimony?

MR. DOWNEY: Mr. Chairman, yesterday the Public Staff, on behalf of the Public Staff and the Applicant, filed a Stipulation with supporting exhibits. If this is the appropriate time, we'd like to move that into evidence.

CHAIRMAN FINLEY: Without objection, we will receive the Stipulation filed yesterday and the supplemental exhibits.

(Whereupon, the Joint Agreement and Stipulation of Settlement and Stipulation Exhibits 1, 2 and 3 were admitted into evidence.)

MR. KAYLOR: Also, Mr. Chairman, I think I asked yesterday, and none of the parties object to putting our witnesses on as a panel, so we'd like to do that, if that's appropriate.

CHAIRMAN FINLEY: Without objection, Duke will call its witnesses as a panel.

MR. FRANKLIN: Thank you, Mr. Chairman. Duke now calls witnesses Kim Smith, Mr. Sasha Weintraub and Mr. Bob Duncan to the stand, please.

KIM H. SMITH; Being first duly sworn,
testified as follows:
SASHA WEINTRAUB; Being first duly sworn,
testified as follows:
ROBERT DUNCAN, II; Being first duly sworn,
testified as follows:

DIRECT EXAMINATION BY MR. FRANKLIN:

Q Mr. Weintraub, will you please state your full name and business address for the record?

A Yes. My name is Alexander J. Weintraub. I'm also known as Sasha Weintraub. And I work at 526 Church Street in Charlotte, North Carolina, for Duke Energy.

Q And what is your position with Duke Energy?

A I am the Vice President of Fuels and System Optimization.

Q And did you cause to be prefiled direct testimony consisting of 14 pages and two exhibits in this docket?

A Yes, I did.

Q Do you have any changes to your prefiled direct testimony?

A No, I do not.

Q If the questions put to you in your direct testimony were asked of you today at the hearing, would your answers be the same?

A Yes, they would.

MR. FRANKLIN: Chairman Finley, we move to have the witness' prefiled direct testimony entered into the record as if given orally from the stand, and also move that the witness' exhibits be identified and marked as prefiled.

CHAIRMAN FINLEY: Mr. Weintraub's direct prefiled testimony consisting of 14 pages shall be copied into the record as if given orally from the stand, and his two exhibits shall be marked for identification as premarked in the filing.

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alexander ("Sasha") J. Weintraub. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am Vice President, Fuels & Systems Optimization for Duke Energy Corporation ("Duke Energy"). In that capacity I am responsible for the procurement of fossil fuels and environmental reagents for the Duke Energy Carolinas, LLC ("DEC" or the "Company") and Progress Energy Carolinas, Inc. ("PEC") (collectively, the "Companies") generation fleet, as well as for the generation fleets of the other Duke Energy regulated utilities. I am also responsible for portfolio management and short term power trading for Duke Energy, and am responsible for the fossil fuel price forecasts used for fuel filings and resource planning purposes for all of Duke Energy's regulated utility subsidiaries, including DEC.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Engineering from Rensselaer Polytechnic Institute, a Master's in Mechanical Engineering from Columbia University, and a Ph.D. in Industrial Engineering from North Carolina State University. From February 2003 until June 2005, I was Director of Coal Marketing and Trading for Progress Fuel Corporation, a former subsidiary of Progress Energy, Inc. ("Progress Energy"). Subsequently, I was Director of Coal for PEC and Progress Energy Florida, Inc. ("PEF"), and before assuming my current position, I was Vice President - Fuels and Power Optimization for PEC and PEF.

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

A. The purpose of my testimony is to describe DEC's fossil fuel purchasing practices, provide fossil fuel costs for the period January 1, 2012 through December 31, 2012 ("test period"), and describe changes forthcoming in the billing period of September 1, 2013 through August, 31 2014 ("billing period"). I also provide an update from a procurement and operations perspective on the Joint Dispatch Agreement ("JDA") that – pursuant to the merger agreement between Duke Energy and Progress Energy ("Merger") – Duke Energy is using to deliver savings to its North and South Carolina customers, as well as fuel savings that DEC has realized to date on behalf of its customers as a result of the Merger.

Q. PLEASE PROVIDE A DESCRIPTION OF THE EXHIBITS TO YOUR TESTIMONY.

A. Weintraub Exhibit 1 summarizes the Company's Fossil Fuel Procurement Practices, and Weintraub Exhibit 2 summarizes monthly contract and spot coal purchases during 2011 and 2012.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes, they were prepared at my direction.

Q. PLEASE PROVIDE A SUMMARY OF DEC'S FOSSIL FUEL PROCUREMENT PRACTICES.

A. A summary of the Company's fossil fuel procurement practices is set out in Weintraub Exhibit 1. The practices of both Duke Energy and Progress Energy, are under review and will be modified to adopt the best practices for the combined company going forward.

Q. **PLEASE DESCRIBE THE COMPANY'S DELIVERED COST OF COAL DURING 2012.**

A. The Company's average delivered coal cost per ton increased 5.3% from $94.52 per ton in 2011 to $99.52 per ton in 2012. The average transportation costs increased approximately 8.6%, from $27.00 per ton in 2011 to $29.32 per ton in 2012.

Q. **PLEASE DESCRIBE THE LATEST TRENDS IN COAL MARKET CONDITIONS.**

A. Coal markets continue to be in a state of flux due to a number of factors, including (1) recent U.S. Environmental Protection Agency ("EPA") regulations for power plants that result in utilities retiring or modifying plants, which lower total domestic steam coal demand, and can result in some plants shifting coal sources to different basins; (2) continuing growth in global demand for both steam and metallurgical coal, which makes coal exports increasingly attractive to U.S. coal producers; (3) continued low gas prices combined with installation of new combined cycle generation by utilities, especially in the Southeast, which also lowers overall coal demand; and (4) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity

Q. **HOW DO YOU EXPECT THESE TRENDS TO AFFECT DEC'S COAL**

BURN AND INVENTORY LEVELS?

A. Due to increasingly lower power prices and reduced demand for coal generation, coal burn projections for 2013 and forward are forecasted to be lower than historical volumes. As an example of the impact, the actual coal burn for DEC's stations in 2012 was just over 10,700,000 tons, approximately 30% less than the average coal burn over the prior five-year period of over 15,900,000 tons. Based on the low coal burns in 2012, as well as the downward projection for coal burns in 2013 as compared to the amount of coal under contract for delivery in 2013, the Company expects coal inventories to be above target levels during 2013. If the Company experiences mild weather and continued low purchased power prices, there likely will be further upward pressure on coal inventories.

Q. **WHAT IS THE PROJECTED AVERAGE DELIVERED COAL COST FOR THE BILLING PERIOD?**

A. Combining coal and transportation costs, the Company projects average delivered coal costs of approximately $98.62 per ton for the billing period. This represents a less than 1% decrease compared to the 2012 actual cost. This cost, however, is subject to change based on (1) changes in oil prices, which impact transportation rates; (2) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts; (3) performance of contract deliveries by suppliers and railroads which may not occur despite the Company's strong contract compliance monitoring process; (4) cost of potential contract volume deferrals in light of declining coal burn projections and high coal inventories; and (5) the

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amount of non-Central Appalachian coal the Company is able to consume.

Q. DOES THE COMPANY'S PRIMARY SOURCE OF COAL CONTINUE TO BE CENTRAL APPALACHIA?

A. No, the Company's primary source of coal supply is no longer the Central Appalachian region. Historically, fuel switching to a different coal basin has been difficult for DEC because coal quality characteristics vary greatly between coal producing basins, and the design of DEC's plants was meant to optimize the use of Central Appalachian coals. The Company's test burn program provides data for determining operational and environmental impacts, as well as the costs—both capital and O&M—to mitigate those impacts. Where the impacts require mitigation, the Company has undertaken engineering and economic studies to determine whether the cost is justified by the savings obtained through burning the non-Central Appalachian coal.

Additionally, as a result of the Merger, the Company can achieve fuel savings by sharing best practices between DEC and PEC for coal blending at their respective coal-fired plants. Specifically, and as mentioned in my testimony submitted on May 20, 2011 in Docket Nos. E-7, Sub 986 and E-2, Sub 998 ("Merger Testimony"), over the past seven years, PEC has made a substantial investment to improve the fuel flexibility of its scrubbed coal units. These investments, which have included improvements to the coal-fired boilers, as well as the balance-of-plant components, have expanded the types of coal that PEC can reliably burn at these units. DEC has been able to learn via the Merger from the PEC practices of consuming non-traditional coals at the PEC coal units without impacting reliability or operations. Because of the sharing of best practices across the DEC and PEC coal generation fleet, DEC can now procure a wide variety of coals for its fleet, resulting in overall fuel savings passed on to customers.

Q. WHAT STEPS IS DEC TAKING TO CONTROL COAL COSTS?

A. The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over many years in limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. Aspects of this procurement strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, and pursuing contract extension options that provide flexibility to extend terms within a particular price band.

The Company expects to address forward year coal requirements later this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels. The Company currently is considering alternatives to help mitigate inventory levels including negotiating contract shipment deferrals/buy-outs, and evaluating coal resell market opportunities. Due to lower coal demand for most of the U.S., however, either of these options would likely be difficult to achieve without paying additional costs to the supplier or incurring sales at potential losses.

Q. PLEASE DESCRIBE DEC'S PROCUREMENT PRACTICES FOR NATURAL GAS.

A. Prior to the close of the Merger, DEC primarily utilized a supply manager to provide needed supply, scheduling and balancing services for its overall natural gas needs. As contemplated during integration planning, the Company began transitioning the natural gas procurement and scheduling activities in-house. Effective November 1, 2012, the Company terminated the gas supply manager agreement and began soliciting and contracting with multiple suppliers, and performing all scheduling and balancing activities in-house. The in-house personnel are responsible for natural gas contracting, competitive procurement, scheduling, and balancing efforts for the gas generation fleet. The Company has implemented gas procurement practices that include periodic Request for Proposals ("RFPs") and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply that supports the Company's combustion turbine ("CT") facilities and the Buck and Dan River combined cycle ("CC") facilities.

Lastly, in December 2012 the Company received approval for the Asset Management and Delivered Supply Agreement ("AMA") between DEC and PEC, which was implemented on January 1, 2013. In the AMA, DEC is the designated Asset Manager that procures and manages the combined gas supply needs for DEC and PEC, and performs the necessary scheduling and balancing on the pipelines.

Q. HOW IS NATURAL GAS DELIVERED TO THE COMPANY'S GENERATING FACILITIES?

A. The Company procures long-term firm transportation that provides natural gas to its generating facilities. In addition, as needed, the Company may procure shorter-term firm pipeline capacity through the capacity release market and market supply options that provide the needed natural gas supply to its generating facilities.

Q. DOES DEC MAINTAIN AN INVENTORY OF NATURAL GAS?

A. The Company does not have an agreement for storage capacity, nor does it maintain an inventory of natural gas. Progress Energy Carolinas, however, does have a storage agreement which was released to DEC as part of the AMA. As the Asset Manager, DEC will procure all the needed supply for the combined Carolinas gas needs and as part of that agreement, will have access to the released storage agreement. On any given day, DEC may utilize the storage to balance and support the Carolinas gas needs.

Q. WHAT CHANGES IN VOLUME DOES THE COMPANY ANTICIPATE WITH NATURAL GAS CONSUMPTION?

A. The Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 42 billion cubic feet ("Bcf") of natural gas in 2012, compared to approximately 10 Bcf in 2011. This increase was driven by the downward trend in the natural gas prices as well as the operation of the Buck CC facility for its first full year ending on December 31, 2012. For 2013, DEC's current forecasted natural gas consumption is approximately 74

Bcf. This forecast is based on current natural gas prices which are forecasted to remain low, as noted later in my testimony, and includes a full year of operations of Dan River CC, which went into commercial service in December 2012

Q. **PLEASE DESCRIBE THE CURRENT STATE OF THE NATURAL GAS MARKET, INCLUDING THE NATURAL GAS PRICES EXPERIENCED DURING THE TEST PERIOD.**

A. The development of shale gas has created a fundamental shift in the nation's natural gas market. Shale gas is natural gas that is trapped within shale formations, and which can provide an abundant source of petroleum and natural gas. Within recent years, improvements in production technologies have allowed greater access to the natural gas trapped in these formations, and has resulted in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for calendar year 2012 was $3.34 per Million British Thermal Units ("MMBtu"), compared to $4.85 per MMBtu in 2011.

Q. **PLEASE DESCRIBE THE OUTLOOK FOR THE NATURAL GAS MARKET, INCLUDING THE EXPECTED NATURAL GAS PRICE TREND FOR THE BILLING PERIOD.**

A. New production from shale gas has contributed to substantial increases in the supply of U.S. marketed natural gas. This increase has outstripped demand growth. The Company expects the shale gas production percentage of total natural gas domestic production to continue to increase over time. The current forward prices for natural gas reflect this continued increase in competitively priced supply with an average forward Henry Hub[1] price of $4.03 per MMBtu through the proposed fuel rates period.

Q. IN LIGHT OF THE COMPANY'S INCREASED USAGE OF NATURAL GAS, WHAT IS THE COMPANY DOING TO MITIGATE THE EFFECTS THAT INCREASING NATURAL GAS PRICES COULD HAVE ON FUEL COSTS?

A. The Company does not currently employ a hedging strategy to fix prices on a portion of the projected natural gas usage. The lower and unpredictable nature of the Company's historical natural gas usage was not suitable for a structured price hedging program. The Company is currently evaluating the feasibility of a hedging program given the increased and more predictable natural gas consumption associated with the addition of the Buck and Dan River CCs. The Company anticipates having further working discussions with the Public Staff–North Carolina Utilities Commission regarding potential hedging program requirements, recommendations, and timing of implementation.

Q. PLEASE EXPLAIN THE JDA BETWEEN DEC AND PEC.

A. As explained in my Merger Testimony, the JDA is an agreement between PEC and DEC where DEC acts as the Joint Dispatcher for DEC's and PEC's power supply resources. The JDA has allowed DEC's and PEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. As a result, the

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

joint dispatch process allows DEC and PEC to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis. The JDA also provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEC and PEC.

Q. HOW DO THE COMPANY'S CUSTOMERS RECEIVE THEIR SAVINGS FROM THE JDA?

A. As I described on pages 12 and 13 of my Merger Testimony, the joint dispatch savings will automatically flow through to the Companies' retail customers through their fuel clauses. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts. Under the joint dispatch process, the energy cost attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the Joint Dispatcher, which are treated as purchases and sales between the Companies. As a result, the energy cost ultimately incurred by DEC and PEC to serve their respective native loads will be equal to the stand-alone costs they would have incurred but for the joint dispatch arrangement, less each utility's share of the joint dispatch savings.

Q. THE COMPANY HAS GUARANTEED A CERTAIN AMOUNT OF MERGER-RELATED SAVINGS TO ITS NORTH CAROLINA RETAIL CUSTOMERS. HOW MUCH SAVINGS HAS DEC ACHIEVED THUS FAR?

A. Through December 2012, the combined merger savings from the JDA and the Companies' fuel procurement activities are $51.9 million. The Company's and PEC's customers are then allocated their share of the combined savings based upon the resource ratios of the combined company. This resource ratio is 58.8% for DEC and 41.2% for PEC through December 2012.

Q. DID ALL OF THE MERGER SAVINGS IN 2012 OCCUR AFTER THE MERGER CLOSE DATE IN JULY 2012?

No. Duke Energy Carolinas and PEC procured coal and reagents in 2011 utilizing joint RFPs assuming a January 2012 Merger close date. The delay in the Merger close in December 2011 occurred after many of the contracts were signed assuming a delivery schedule beginning in January 2012. These contracts were delivered to DEC coal stations and either stockpiled or utilized in limited testing plans. After the Merger close, the savings from these same contracts were shared between DEC and PEC as specified in the merger stipulation agreement. The Companies propose that the pre-merger savings be shared with PEC utilizing the sharing ratio for savings that occurred from July to December 2012.

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

A. Both DEC and PEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider 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 order to determine the most economic and reliable means of serving their customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

(Whereupon, Weintraub Exhibits 1
and 2 were identified as premarked.)

MR. FRANKLIN: Thank you, Chairman Finley.

BY MR. FRANKLIN:

Q Mr. Weintraub, did you prepare a summary of your testimony today?

A Yes, I did.

Q Will you please read that summary to the Commission?

A Yes, sir. (Summary read into the record.)

Sasha Weintraub's Direct Testimony Summary

Docket No. E-7, Sub 1033

The purpose of my testimony is to describe DEC's fossil fuel purchasing practices; provide fossil fuel costs for the period January 1, 2012 through December 31, 2012; and describe changes forthcoming in the billing period September 1, 2013 through August, 31 2014. I also will provide an update from a procurement and operations perspective on the Joint Dispatch Agreement, or, JDA.

The Company continues to follow the fossil fuel procurement practices that it has historically followed. The practices of both Duke Energy and Progress Energy are under review and will be modified to adopt the best practices for the combined company going forward. The Company's average delivered coal cost per ton increased 5.3% from $94.52 per ton in 2011 to $99.52 per ton in 2012. The average transportation costs increased approximately 8.6%, from $27.00 per ton in 2011 to $29.32 per ton in 2012.

Combining coal and transportation costs, the Company projects average delivered coal costs of approximately $98.62 per ton for the billing period. This represents less than a 1% decrease compared to the 2012 actual cost.

Additionally, as a result of the Merger, the Company can achieve fuel savings by sharing best practices between DEC and PEC for coal blending at their respective coal-fired plants. DEC has been able to learn via the merger from the PEC practices of consuming non-traditional coals at the PEC coal units without impacting reliability or operations.

Regarding natural gas, DEC consumed approximately 42 billion cubic feet, or BCF, of natural gas in 2012, compared to approximately 10 Bcf in 2011. For 2013, DEC's current forecasted natural gas consumption is approximately 74 Bcf. DEC does not currently employ a hedging strategy to fix prices on a portion of its projected natural gas usage. The Company expects the shale gas production percentage of total natural gas domestic production to continue to increase over time.

The JDA is an agreement between PEC and DEC where DEC acts as the Joint Dispatcher for DEC's and PEC's power supply resources. The JDA has allowed DEC's and PEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. The JDA also provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEC and PEC. Through December 2012, the combined merger savings from the JDA and the DEC's and PEC's fuel procurement activities were $51.9 million.

The joint dispatch savings will automatically flow through to the Companies' retail customers through their fuel clauses. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts.

This concludes my testimony summary.

MR. FRANKLIN: Thank you, Mr. Weintraub.

BY MR. FRANKLIN:

Q Ms. Smith, please state your full name and business address for the record.

A My name is Kim H. Smith, and I work at 526 South Church Street, Charlotte, North Carolina, for Duke Energy.

Q And what is your position with Duke Energy?

A I'm a Rates Manager.

Q And did you cause to be prefiled direct testimony consisting of 20 pages and six exhibits and six revised exhibits in this case?

A Yes, I did.

Q Do you have any changes to your prefiled direct testimony?

A No, I do not.

Q If the questions put to you in your direct testimony were asked of you today, would your answers be the same?

A Yes, they would.

MR. FRANKLIN: Chairman Finley, we move to have the witness' prefiled direct testimony entered into the record as if given orally from the stand, and also move that the witness' exhibits and revised exhibits be identified and marked as prefiled.

CHAIRMAN FINLEY: Ms. Smith's direct prefiled testimony consisting of 20 pages shall be copied into the record as if given orally from the stand. Her six exhibits and six revised exhibits shall be marked for identification as premarked in the filing.

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kim H. Smith. My business address is 526 South Church Street, Charlotte, North Carolina.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Marshall University with a Bachelor of Business Administration degree, and received a Master of Business Administration degree from the University of Charleston. I am a certified public accountant licensed in the state of North Carolina. I began my career with DEC in 2006 as an external reporting manager. Since I joined the Rate Department in 2008 as Rates Manager I have been responsible for providing regulatory support for retail and wholesale rates, providing guidance on DEC's and Progress Energy Carolinas' ("PEC") Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") compliance and cost recovery applications, and energy efficiency cost recovery process.

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

A. I am responsible for providing regulatory support for retail and wholesale rates, and providing guidance on DEC's fuel and fuel-related cost recovery application in North Carolina, and its fuel cost recovery application in South Carolina.

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

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC" or the "Commission") in DEC's 2010 and 2012 REPS compliance and cost recovery applications, Docket No. E-7, Subs 984 and 1008, respectively. In addition, I provided supplemental testimony in PEC's REPS cost recovery application in Docket No. E-2, Sub 1020.

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

A. Yes. Duke Energy Carolinas' 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 Smith Exhibits 1 through 6, along with supporting workpapers. The test period used in supplying this information and data is the twelve months ended December 31, 2012 ("test period"), and the billing period is September 1, 2013 through August 31, 2014 ("billing period").

Q. WHAT IS THE SOURCE OF THE ACTUAL INFORMATION AND DATA FOR THE CALENDAR YEAR 2012 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

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records. These books, records, and reports of the Company are subject to review by the appropriate regulatory agencies in the three jurisdictions 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 SMITH EXHIBITS 1 THROUGH 6 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

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

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

Exhibit 2:

Schedule 1: Fuel and Fuel-Related Costs Factors - reflecting a 92.84% proposed nuclear capacity factor and projected MWH sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 92.84% nuclear capacity factor and adjusted test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 89.79% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for pressurized water reactors and adjusted test period sales.

Exhibit 3:

Page 1: Calculation of the Proposed Composite EMF rate.

Page 2: Calculation of the EMF for residential customers.

Page 3: Calculation of the EMF for general service/lighting. customers.

Page 4: Calculation of the EMF for industrial customers.

Exhibit 4: Megawatt hour ("MWH") Sales, Fuel Revenue, and Fuel and Fuel-Related Expense, as well as System Peak for the test period.

Exhibit 5: Nuclear Capacity Ratings

Exhibit 6: December 2012 Monthly Fuel Reports.

1) December 2012 Monthly Fuel Report required by NCUC Rule R8-52.

2) December 2012 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

Q. **PLEASE EXPLAIN WHAT IS SHOWN ON SMITH EXHIBIT 1.**

A. Smith Exhibit 1 presents a summary of fuel and fuel-related cost factors, including the current fuel and fuel-related cost factors, the fuel and fuel-related cost factors using the methodology approved in the Company's last general rate case in Docket No. E-7, Sub 989, the fuel and fuel-related cost factors using the NERC five-year average nuclear capacity factor, and the proposed fuel and fuel-related cost factors.

Q. WHAT FUEL FACTORS DOES THE COMPANY PROPOSE FOR INCLUSION IN RATES FOR THE BILLING PERIOD?

A. The Company proposes that fuel and fuel-related costs factors for residential, general service/lighting, and industrial customers of 2.1877¢, 2.2277¢, and 2.2533¢ per kWh, respectively, be reflected in rates during the billing period. The factors the Company proposes in this proceeding incorporate a 92.84% nuclear capacity factor as testified to by Company Witness Duncan, projected fossil fuel costs as testified to by Company Witness Weintraub, projected nuclear fuel costs as testified to by Company Witness Culp, and projected reagents costs as testified to by Company Witness Miller. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Smith Exhibit 1 are:

	Residential	General	Industrial
	cents/KWh	cents/KWh	cents/KWh
Total adjusted Fuel and Fuel Related Costs cents/kWh	2.2323	2.3559	2.3952
EMF Decrement cents/kWh	(0.0382)	(0.1099)	(0.1216)
EMF Interest Decrement cents/kWh	(0.0064)	(0.0183)	(0.0203)
Net Fuel and Fuel Related Costs Factors cents/kWh	2.1877	2.2277	2.2533

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 no impact on customers' bills. Line 1 below shows the proposed fuel and fuel-related cost factors in this proceeding, which includes the benefits of merger-related fuel savings. Line 2 shows the existing fuel and fuel-related cost factors including the merger fuel-related savings rider (without gross receipts tax and regulatory fee). When the existing factors expire on August 31, 2013, they will be replaced with the proposed net fuel and fuel-related costs factors of the same amounts.

	Residential	General	Industrial
	cents/KWh	cents/KWh	cents/KWh
1 Proposed Net Fuel and Fuel-Related Costs Factors cents/kWh	2.1877	2.2277	2.2533
2 Existing Net Fuel and Fuel-Related Costs Factors including MFS Rider cents/kWh	2.1877	2.2277	2.2533

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

A. A number of factors contribute to the proposed net fuel and fuel-related costs factors remaining unchanged for all customer classes, including reduced fuel costs due to greater availability of gas generation, the benefits of joint dispatch of the combined portfolio of DEC and PEC resources, and the incorporation of the return of $47 million of over-collected fuel costs for the calendar year 2012 into the proposed fuel factors, compared to $19 million of under-collected fuel costs that were included in existing fuel rates. This was offset by higher projected fuel prices and higher sales, which result in more frequent operation of DEC's higher cost generating units. For example, Company Witness Culp explains that the billing period price of 0.676 ¢ per kWh for nuclear fuel will be about 18% higher than experienced during the test period. Despite the higher projected nuclear fuel costs, however, those costs represent approximately 15% of system fuel costs while nuclear fuel generation represents approximately 48% of the expected system generation and purchased power mix.

As discussed by Company Witness Weintraub, the proposed fuel and fuel-related cost factors include an average delivered cost for coal for the billing period of $98.62 per ton, which is less than 1% lower than the average delivered cost of coal during the test period. In addition, Witness Weintraub notes an increase in natural gas prices as evidenced by the Henry Hub forward price of $4.03 per Million British Thermal Units used in the proposed fuel rates.

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

A. For this filing, DEC used an hourly dispatch model in order to generate its fuel forecasts. This hourly dispatch model considers the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities. In addition, the model dispatches DEC's and PEC's generation resources with the joint dispatch optimizing the generation fleets of DEC and PEC.

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

A. Exhibit 2 is divided into three schedules. Schedule 1 sets forth the determination of the prospective fuel and fuel-related costs. The calculation used the nuclear capacity factor of 92.84% as explained by Company Witness Duncan in his testimony, and forecasted MWH sales for the billing period along with the assumptions discussed above to determine the proposed fuel and fuel-related costs factors to be reflected in rates for service during the billing period.

Schedule 2 also uses the capacity factor of 92.84% along with adjusted test period KWH generation, as prescribed by NCUC Rule R8-55 (e)(3), which requires the use of the methodology adopted by the Commission in the Company's last general rate case.

The capacity factor shown on Schedule 3 is prescribed in NCUC Rule R8-55 (d)(1). The normalized five-year national weighted average NERC capacity factor is 89.79%. This capacity factor is based on NERC's 2007 through 2011 Generating Availability Report ("NERC Report") for pressurized water reactors. Typically, the Company obtains this figure from NERC's Generating Unit Statistical Brochure ("NERC Brochure"). The most recent NERC Brochure, however, has not yet been published, and as a result, the Company computed this number from the NERC Report. Adjusted test period KWH generation was also used for schedule 3 per NCUC Rule R8-55 (d)(1).

Page 2 of Exhibit 2, Schedules 1, 2, and 3, presents the calculation of the proposed fuel and fuel-related costs factors by customer class resulting from the allocation of renewable and cogeneration power capacity costs by customer class on the basis of production plant as described on page 89, paragraph 17 of the Order in the Company's general rate case in Docket No. E-7, Sub 909.

Page 3 of Exhibit 2, Schedules 1, 2, and 3, shows the calculation of the Company's proposed fuel and fuel-related cost factors for the residential, general service/lighting and industrial classes, exclusive of gross receipts tax and regulatory fee, using the uniform percentage average bill adjustment method.

Q. PLEASE SUMMARIZE THE METHOD USED TO ADJUST TEST PERIOD KWH GENERATION IN SMITH EXHIBIT 2 SCHEDULES 2 AND 3.

A. The steps used to adjust test period generation, based on the Company's last general rate case methodology, are as follows:

(1) Total generation was calculated by applying a five-year average line loss/company use factor to the forecasted MWH sales for the billing period of September 2013 through August 2014.

(2) Estimated combustion turbine ("CT") generation reflects a three-year average.

(3) Estimated combined-cycle ("CC") generation for the billing period was included.

(4) For nuclear generation, the Company used the normalized five-year national industry average NERC capacity factor of 89.79%, as well as the capacity factor of 92.84% also used to calculate the prospective fuel and fuel-related costs.

(5) Conventional hydroelectric ("hydro") generation was based on the Company's historical 31-year median hydro generation for the period 1982 through 2012. Pumped storage hydro generation was based on the

five-year average pumped storage operation at Jocassee and Bad Creek pumped storage facilities.

(6) Expected renewable generation and renewable purchased power for the billing period was included.

(7) Residual generation is total generation as calculated in Step (1) above, less generation calculated above for natural gas, nuclear, hydro, and renewables, and further reduced by purchased and interchange power estimated at the test period level. The residual generation is obtained from the coal-fired generating units.

Q. SMITH EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD OVER/(UNDER) RECOVERY BALANCE AND THE EMF RATE. HOW DID FUEL EXPENSES COMPARE WITH FUEL REVENUE DURING CALENDAR YEAR 2012?

A. Smith Exhibit 3, Pages 1 through 4, demonstrates that for the test period, the Company experienced an over-recovery for residential, general service/lighting, and industrial customer classes of $8.1 million, $24.3 million, and $14.9 million respectively. The over-collected fuel amounts result in EMF decrements of 0.0382¢, 0.1099¢ and 0.1216¢ per kWh respectively, for residential, general service/lighting, and industrial customer classes, based on adjusted test period sales by customer class. The over-collection resulted in interest of $1.3 million, $4.0 million, and $2.5 million for EMF decrements of 0.0064¢, 0.0183¢ and 0.0203¢ per kWh respectively, for residential, general service/lighting, and industrial customer classes, based on adjusted test period sales by customer class.

The over/(under) collection amount was determined each month by comparing the amount of fuel revenue collected for each class, based on actual monthly sales, to incurred actual fuel costs allocated to customer classes based on fixed allocation percentages each month. The allocation percentages for each customer class were based on the customer class allocation of fuel costs in the Company's previous fuel proceeding based on the uniform percentage average bill adjustment method.

Exhibit 3 also includes an adjustment that the Company proposes to make to the over-collection balance for DEC for calendar year 2012 in order to share certain merger fuel-related savings with PEC customers. In his testimony, Company Witness Weintraub describes the circumstances under which certain merger fuel-related savings were accomplished during January through June 2012, prior to the closing date of the merger of Duke Energy Corporation and Progress Energy, Inc. ("Merger"). The Company has reported these savings to the Commission, totaling $10.7 million, on its monthly fuel filing "Schedule 11" report of merger fuel-related savings. The Company, however, has not reflected on its books the sharing of these costs with PEC. Upon approval by the Commission to adjust the over-collection for calendar year 2012 to reflect the sharing of merger fuel-related savings achieved during the period prior to Merger close, the Company will make the appropriate entries on its books to reflect the sharing of the savings. As shown on Smith Exhibit 3, Page 1 of 4, line 14, the North Carolina retail portion of the amount to be shared with PEC is $2.3 million.

Exhibit 3 also includes a correction related to the avoided cost associated with purchases of energy from renewable resources in accordance with N.C. Gen. Stat. § 62.133.2(a1)(6). The incremental cost of renewable purchased power (in excess of avoided cost) is recoverable through the Company's REPS rider in accordance with N.C. Gen. Stat. § 62-133.7(h). During the preparation of the Company's fuel and REPS filings, it was discovered that some renewable purchased power transactions that occurred in 2012 were not properly split between avoided cost and incremental cost. As a result, the amount of avoided cost included in the monthly fuel filings was overstated and the amount of incremental cost recoverable through REPS was understated.

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

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Smith Exhibit 4 sets forth test period actual MWH sales, the customer growth MWH adjustment, and the weather MWH adjustment. Test period MWH sales were normalized for weather using a 10-year period, as used in DEC's last general rate case (Docket No. E-7, Sub 989) and the last fuel proceeding (Docket No. E-7, Sub 1002). Customer growth was also determined using the methods adopted in the Company's last general rate case and used in the last fuel proceeding. Smith Exhibit 4 also sets forth actual test period fuel-related revenue and fuel expense on a total Company basis and for North Carolina Retail. Finally, Smith 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 SMITH EXHIBIT 5.**

A. Smith Exhibit 5 sets forth the capacity ratings for each of DEC's nuclear units, in compliance with Rule R8-55 (e)(12). The ratings for McGuire Units 1 and 2 have changed from 1,100 MWs each in the Company's last general rate case to 1,129 MWs in this proceeding due to increases associated with low pressure turbine upgrades effective December 31, 2012.

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

A. Yes. As shown on Smith Exhibit 6, DEC's test year actual fuel and fuel-related costs were 2.2509¢ per kWh. Key factors in DEC's ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of DEC's and PEC's respective skills in procuring, transporting, managing and blending fuels, procuring reagents, and the increased and broader purchasing ability of the combined Company as well as the joint dispatch of DEC's and PEC's generation resources. Company Witness Duncan discusses the performance of DEC's nuclear generation fleet, and Company Witness Miller discusses the performance of the fossil and hydro fleet, as well as the market conditions of chemicals that DEC uses to reduce emissions. Company Witness Weintraub discusses the fossil fuel procurement strategies and key factors related to the Merger, and Company

Witness Culp discusses DEC's nuclear fuel costs and procurement strategies.

Q. IN DEVELOPING THE PROPOSED FUEL AND FUEL-RELATED COST FACTORS, WERE THE FUEL COSTS ALLOCATED IN ACCORDANCE WITH N.C. GEN. STAT. § 62-133.2(A2)?

A. Yes, the costs for which statutory guidance is provided are allocated in compliance with N.C. Gen. Stat. § 62-133.2(a2). These costs are described in subdivisions (4), (5) and (6) of N.C. Gen. Stat. § 62-133.2(a1). Subdivision (4) includes purchased power non-capacity costs subject to economic curtailment or dispatch and is allocated based on MWH sales. Subdivision (5) includes renewable capacity costs and is based upon the production plant allocator from the cost of service study in the Company's most recent general rate case. Subdivision (6) includes cogeneration and independent power producer capacity costs. The allocation methods for subdivisions (4), (5) and (6) are found on page 89, paragraph 17 of the Company's general rate case Order in Docket E-7, Sub 909.

Q. HOW ARE THE OTHER FUEL COSTS ALLOCATED FOR WHICH THERE IS NO SPECIFIC GUIDANCE IN N.C. GEN. STAT. § 62-133.2(A2)?

A. The costs for which statutory guidance is not provided are allocated using the uniform percentage average bill adjustment methodology in setting fuel rates in this fuel proceeding. The Company proposes to use the same uniform percentage average bill adjustment methodology to recover its proposed increase in fuel and fuel-related costs as it did in the Company's 2012 fuel and fuel-related cost recovery proceedings.

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

A. Smith Exhibit 2, Page 3 of Schedule 1 shows the Company's proposed fuel and fuel-related cost factors for the residential, general service/lighting and industrial classes, exclusive of gross receipts tax. The uniform bill percentage change of 0.00% was calculated by dividing the fuel and fuel-related cost increase of $151,634 for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $4,624,265,623. The cost increase of $151,634 was determined by comparing the total proposed fuel rate per kWh to the total fuel rate per kWh currently being collected from customers including the merger fuel-related savings decrement rider, and multiplying the resulting increase in fuel rate per kWh by projected North Carolina retail kWh sales for the billing period. The proposed fuel rate per kWh represents the rate necessary to recover projected period fuel costs for the billing period (as computed on Smith Exhibit 2, Schedule 1), minus the current over-collected fuel cost at the end of 2012 (as computed on Exhibit 3). The dollar amount of increase in fuel costs is insignificant, and as a result, the uniform percent change rounds to 0.00%. As such, the Company elected not to compute an associated increase in cents per kWh related to the dollar amount of the cost increase. Smith 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 SMITH EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. Smith Exhibit 2, Page 3 of Schedules 1, 2, and 3 uses the same calculation, but with the methodology as prescribed by NCUC Rule R8-55 (e)(3) and NCUC Rule R8-55 (d)(1), respectively, with the breakdown shown on Smith Exhibit 2, Page 2 of Schedules 2 and 3. The equal percent increase or decrease for each customer class is applied to current annual revenues by customer class to determine a dollar amount of increase or decrease for each customer class. The dollar increase or decrease is divided by the projected billing period sales for each class to derive a cents per kWh increase. The current total fuel and fuel-related cost factors for each class are increased or decreased by the proposed cents per kWh increases or decreases to get the proposed total fuel and fuel-related cost factors. The proposed total factors are then separated into the prospective and EMF components by subtracting the EMF components for each customer class (as computed on Smith Exhibit 3, Page 2, 3, and 4) to derive the prospective component for each customer class. This breakdown is shown on Smith Exhibit 2, Page 2 of Schedules 1, 2, and 3.

Q. HAS DEC'S ANNUAL INCREASE IN THE AGGREGATE AMOUNT OF THE COSTS IDENTIFIED IN SUBDIVISIONS (4), (5), AND (6) OF

N.C. GEN. STAT. § 62-133.2(a1) EXCEEDED 2% OF ITS NORTH CAROLINA RETAIL GROSS REVENUES FOR 2012?

A. No. When JDA-related costs are excluded from the purchased power calculation, the amount recoverable in the Company's proposed rates under the relevant sections of N.C. Gen. Stat. § 62-133.2(a1) does not increase by more than 2% of DEC's gross revenues for its North Carolina retail jurisdiction for calendar year 2012. North Carolina General Statutes § 62-133.2(a2) limits the amount of annual increase in certain purchased power costs identified in § 62-133.2(a1) that the Company can recover to 2% of its North Carolina retail gross revenues for the preceding calendar year. In determining whether purchased power costs included in the Company's proposed rates should be limited, DEC performed its evaluation excluding the costs directly related to JDA transactions between DEC and PEC, which are providing merger savings that the Company is passing through to its customers. As explained by Company Witness Weintraub, the JDA has allowed DEC's and PEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. The JDA was approved by the Commission in the Merger docket, and without it, these specific purchased expenses between DEC and PEC would not exist. As a result, the Company has included the full amount of its purchased power costs, including these transactions, in its cost recovery application.

Q. THE COMPANY'S MERGER FUEL-RELATED SAVINGS RIDER BECAME EFFECTIVE ON SEPTEMBER 1, 2012 AND IS SET TO

EXPIRE ON AUGUST 31, 2013. HOW ARE MERGER FUEL-RELATED SAVINGS HANDLED IN THE COMPANY'S PROPOSED FUEL RATES?

A. The expiration date of the merger fuel-related savings rider was set to align with the effective date of the Company's next fuel rate change, which is September 1, 2013. The rider was initially necessary to begin flowing merger fuel-related savings to customers promptly upon the close of the Merger. Since the Merger close, the fuel savings have been reflected on the Company's books in the form of lower fuel costs. The Company's true-up to actual fuel costs, including merger savings during the period January through December 2012, are reflected in the Company's over collection balance as shown on Exhibit 3. In addition, the projected fuel costs on which the Company's proposed fuel rates are based include expected merger fuel-related savings for the billing period. As a result, the Company has not proposed a separate merger fuel-related savings rider beyond August 2013.

Q. **CAN YOU IDENTIFY WHERE IN THIS FILING THESE SAVINGS ARE INCLUDED?**

A. As Company Witness Weintraub testified in Docket No. E-7, Sub 986, merger fuel-related savings automatically flow through to the DEC's retail customers through the fuel and fuel-related cost component of customer's rates. As described above, actual merger savings during the calendar year 2012 are included in the EMF portion of the proposed fuel and fuel-related cost factors. In addition, in the prospective component of the factors, the projected merger savings related to procuring coal and reagents, lower transportation costs, lower gas capacity costs and coal blending are reflected in the cost of fossil fuel. Projected joint dispatch savings, which are the result of using the combined systems' lowest available generation to meet total customer demand, are also reflected in the cost of fossil fuel as well as the projected cost purchases and sales that include the purchases and sales between DEC and PEC.

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

A. Yes. The work papers supporting the calculations, adjustments and normalizations are included with the filing in this proceeding.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

(Whereupon, Smith Exhibits 1-6 and
Smith Revised Exhibits 1-6 were
identified as premarked.)

BY MR. FRANKLIN:

Q Ms. Smith, did you prepare a summary of your testimony today?

A Yes, I did.

Q Can you please read that summary to the Commission?

A Yes. The purpose of my testimony is to present the information and data required by North Carolina General Statute, Section 62-133.2(c) and (d), and Commission Rule R8-58 (sic) as set forth in Smith Exhibits 1 through 6, along with supporting workpapers. The test period used in supplying this information and data is the 12 months ended December 31, 2012. The billing period is September 1, 2013 through August 31, 2014.

Actual test period kilowatt hour generation, kilowatt hour sales, fuel-related revenues and fuel-related expenses were taken from the Company's books and records. These books and records and reports of the Company are subject to review by the appropriate regulatory agencies in the three jurisdictions that regulate the Company's electric rates.

The Company proposes that fuel and fuel-related cost factors for residential, general service/lighting and industrial customers of 2.1877 cents, 2.2277 cents and 2.2533 cents per kilowatt hour respectively be reflected in rates during the billing period.

If the proposed fuel and fuel-related cost factors in my direct testimony are approved, there will be no impact on customers' bills.

A number of factors contribute to the proposed net fuel and fuel-related cost factors remaining unchanged for all customer classes, including reduced fuel cost due to greater availability of gas generation, the benefits of joint dispatch of the combined portfolio of DEC and PEC resources, and the incorporation of the return of $47 million of over-collected fuel costs for the calendar year 2012 into the proposed fuel factors, compared to $19 million of under-collected fuel costs that were included in the existing fuel rates.

Key factors in Duke Energy Carolinas' ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio mix of nuclear, coal, natural gas and hydro; lower coal and natural gas prices; the capacity factors of its nuclear fleet and fuel procurement strategies that mitigate against volatility and supply costs. Other key factors include the combination of DEC's and PEC's respective skills in procuring, transporting, managing and blending fuels, procuring reagents, and the increased and broader purchasing ability of the combined Company, as well as a joint dispatch of DEC's and PEC's generation resources.

Upon approval by the Commission to adjust the over-collection for calendar year 2012 to reflect the sharing of merger related savings achieved during the period prior to the merger close, the Company will make the appropriate entries on its books to reflect the sharing of these savings.

The Company's true-up to actual fuel costs, including merger savings during the period January through December 2012, are reflected in the Company's over-collection balance as shown on Exhibit 3. In addition, the projected fuel costs on which the Company's proposed fuel rates are based include expected merger fuel-related savings for the billing period. As a result, the Company has not proposed a separate merger fuel-related savings rider beyond August 2013.

The actual merger savings during the calendar year 2012 are included in the EMF portion of the proposed fuel and fuel-related cost factors. In addition, in the prospective component of the factors, the projected merger savings related to procuring coal and reagents, lower transportation costs, lower gas capacity costs and coal blending are reflected in the cost of fossil fuel.

This concludes my testimony summary.

MR. FRANKLIN: Thank you, Ms. Smith.

BY MR. FRANKLIN:

Q Mr. Duncan, would you please state your full name and business address for the record.

MR. RUNKLE: Excuse me, counsel. Commissioner, I think that the witness misread the Commission Rule on the fourth line of her summary testimony, just to be clear for the record. It's Commission Rule R8-55.

MS. SMITH: Oh, I'm sorry. Did I say --

MR. RUNKLE: You said something else.

CHAIRMAN FINLEY: All right. We'll note the correct -- R8-55 is the correct rule. Thank you.

BY MR. FRANKLIN:

Q Mr. Duncan, will you please state your full name and business address for the record?

A Yes. Robert Joseph Duncan, II, also known as Bob Duncan.

Q And what is your position with Duke Energy?

A Senior Vice President, Nuclear Operations, responsible for the McGuire and Catawba nuclear stations.

Q And did you cause to be prefiled direct testimony consisting of 11 pages and one exhibit in this docket?

A Yes, I did.

Q And did you also cause to be prefiled supplemental testimony consisting of nine pages in this docket?

A Yes, I did.

Q Do you have any changes to your prefiled direct or supplemental testimonies?

A I have no changes to either.

Q If the questions put to you in your direct or prefiled supplemental testimony were asked of you today at the hearing, would your answers be the same?

A Yes, they would.

MR. FRANKLIN: Chairman Finley, we move to have the witness' prefiled direct and supplemental testimony entered into the record as if given orally from the stand, and we also move that the witness' confidential exhibit actually be identified and marked as prefiled.

CHAIRMAN FINLEY: All right. Mr. Duncan's direct prefiled testimony of 11 pages shall be copied into the record as though given orally from the stand, and his one confidential exhibit shall be so marked for identification, and his supplemental testimony consisting of nine pages shall be copied into the record as though given orally from the stand.

(Whereupon, the prefiled direct and supplemental testimony of Robert J. Duncan, II was copied into the record as if given orally from the stand.)

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert J. ("Bob") Duncan, II. 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 Carolinas, LLC's ("DEC" or the "Company") McGuire Nuclear Station ("McGuire") in Mecklenburg County, North Carolina, Catawba Nuclear Station ("Catawba") in York County, South Carolina, and Progress Energy Carolinas, Inc.'s ("PEC") Shearon Harris Nuclear Generating Station ("Harris") in Wake County, North Carolina.

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES?

A. As Senior Vice President of Nuclear Operations for McGuire, Catawba, and Harris, I am responsible for providing direct oversight for the day-to-day safe and reliable operation of those nuclear stations.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor's degree in Nuclear Engineering from the University of Florida at Gainesville and a Master's in Business Administration from the University of North Carolina at Chapel Hill. I began my career with Progress Energy, Inc. ("Progress Energy") in 1980 as a start-up engineer at Harris, and I received my senior reactor operator certification in 1997. Through the years I have held leadership roles in several areas within the nuclear organization including engineering, mechanical systems, technical support, reactor and performance engineering, and plant management. In 2007, I was named vice president of Harris, where I was responsible for managing all activities to ensure the safe and efficient operation of the facility. I also served as vice president of nuclear operations for Progress Energy from 2008 to 2010, and again from 2011 to July 2012. In that role, I was responsible for ensuring safe and reliable operations, improving work efficiencies, and effectively aligning practices, policies, and procedures. From 2010 to 2011, I was on special assignment as vice president of PEC's Robinson Nuclear Generating Station. I assumed my current position following the merger between Duke Energy Corporation and Progress Energy in July 2012.

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 McGuire and Catawba nuclear stations, as well as DEC's Oconee Nuclear Station ("Oconee"), located in Oconee County, South Carolina, during the test period of January 1, 2012 through December 31, 2012 ("test period"). I also discuss the nuclear capacity factor being proposed by DEC and used in this proceeding for determining the fuel factor to be reflected in rates during the billing period of September 1, 2013 through August 31, 2014 ("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 the Company's nuclear units through the billing period. This exhibit represents the Company's current plan, which is subject to change based on fluctuations in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEC'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 5,200 megawatts ("MWs") of generating capacity, made up as follows:

Oconee -	2,538 MWs
McGuire -	2,258 MWs [1]
Catawba -	435 MWs [2]

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

A. The Company's nuclear fleet consists of three generating stations and a total of seven units. Oconee began commercial operation in 1973 and was the first nuclear station designed, built, and operated by DEC. It has the distinction of being the second nuclear station in the country to have its license, originally issued for 40 years, renewed for up to an additional 20 years by the Nuclear Regulatory Commission ("NRC"). The license renewal, which was obtained in 2000, extends operations to 2033, 2033, and 2034 for Oconee Units 1, 2, and 3 respectively.

McGuire began commercial operation in 1981, and Catawba began commercial operation in 1985. In 2003, the NRC renewed the licenses for McGuire and Catawba for up to an additional 20 years each. This renewal extends operations until 2041 for McGuire Unit 1 and 2043 for McGuire Unit 2,

[1] As of December 31, 2012 – includes capacity increases associated to low pressure turbine upgrades.
[2] Reflects DEC's 19.2% ownership of Catawba Nuclear Station.

and Catawba Units 1 and 2. The Company jointly owns Catawba with North Carolina Municipal Power Agency Number One, North Carolina Electric Membership Corporation, and Piedmont Municipal Power Agency.

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

A. The primary objective of DEC's nuclear generation department is to safely provide reliable and cost-effective electricity to the Company's Carolinas customers. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with detailed procedures. 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 effectively ready the plant for operation until the next planned outage.

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

A. Overall, DEC's nuclear stations operated well during 2012, and supplied 62% of the power used by its Carolinas customers in the test period. The seven nuclear units operated at a system average capacity factor of 91.85%. The capacity factor for McGuire Unit 1 was 104.67%, an annual record for the unit. McGuire Unit 2 concluded a 528-day continuous run leading up to the fall refueling outage – the longest continuous run in McGuire history. This also ended a 335-day continuous dual-unit run setting another station record. Oconee Unit 3 set a unit record by concluding a 446-day continuous run leading up to its refueling outage, and Oconee set a new record in the 2nd quarter of 2012 with a capacity factor of 102.68%.

Also of note, in 2012 the Company implemented the second upgrade of an integrated digital reactor protection system and engineering safeguards ("RPS/ES") technology on Oconee Unit 3. The Company was able to reduce the length of the outage on this second upgrade by 14 days, and more efficiently completed the refueling and maintenance work due in large part to the application of lessons learned from the Unit 1 RPS/ES implementation. As a follow-up to the Unit 1 upgrade, the Company was recognized and received multiple awards, including the "Engineering Project of the Year" award at the 13th Annual Platt's Global Energy Awards ceremony, and the Nuclear Energy Institute's "Best of the Best" Top Industry Practice award.

Q. HOW DOES THE COMPANY'S NUCLEAR FLEET COMPARE TO INDUSTRY AVERAGES?

A. Utilizing the North American Electric Reliability Council's ("NERC") Generating Availability Report ("NERC Report"), which is considered by the North Carolina Utilities Commission in establishing fuel factors in proceedings such as this, the Company's nuclear fleet compares favorably. The most recently published NERC Report, which represents the period 2007 through 2011, indicates an average capacity factor of 89.79%. Typically, the Company obtains this figure from NERC's Generating Unit Statistical Brochure ("NERC Brochure"). The most recent NERC Brochure, however, has not yet been published, and as a result, the Company computed this number from the NERC Report. The 89.79% capacity factor represents an average of comparable units, which are pressurized water reactors on a capacity-rated basis with capacity ratings at and above 800 MWs. The Company's capacity factor of 91.85% for 2012 exceeds the NERC average of 89.79%. Overall, the Company's system average nuclear capacity factor has been above 90% for 13 consecutive years. These performance results support DEC's continued commitment to achieving high performance without compromising safety and reliability.

Q. WHAT IMPACTS A UNIT'S AVAILABILITY AND WHAT IS THE COMPANY'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 DEC's nuclear system. The Company's nuclear performance has improved significantly over the course of the years of operating its nuclear fleet. In particular, shorter refueling outages and improved forced outage rates have contributed to increasing the capacity factors achieved by the Company's nuclear fleet as discussed above.

The Company's scheduling philosophy is to plan for a best possible outcome with minimal contingency days included in the outage plan. When an extension is necessary, however, the Company believes that such extensions result 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, 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 return the unit to service as quickly as possible.

Q. WERE OUTAGE EXTENSIONS REQUIRED FOR REFUELING AND MAINTENANCE OUTAGES THAT OCCURED AT THE COMPANY'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. Yes, there were five refueling and maintenance outages during the test period and additional time was required during three of these outages to complete activities needed for on-line reliability. The spring 2012 refueling and maintenance outage on Catawba Unit 2 required an 11-day extension most notably due to a loss of offsite power event at the station, which I describe in more detail later in my testimony. Other efforts included in the refueling outage for Unit 2 included replacing service water and cooling water piping, which completed phase II of a major project effort, and valve conversions and replacements.

In the fall of 2012, Oconee Unit 1 began a refueling and maintenance outage which required a five-day extension due to work associated with vent valve replacement. Major work activities included with this refueling outage were removing reactor vessel internals for extensive inspections, seal replacements on 1A1 and 1B2 reactor core pumps, and installation of a redundant bus line differential relaying to CT-1 transformer.

The McGuire Unit 2 refueling and maintenance outage took place in the fall and required a 31-day extension. The most prominent delays involved challenges with major projects incorporated into the outage duration window, rework required due to foreign material, turbine bearing damage discovered during startup, and an isolation valve problem that required returning to Mode 3 for repair. This refueling and maintenance outage was a milestone effort in the Company's uprate program involving replacement of the rotor for the high pressure turbine and upgraded measurement uncertainty recapture instrumentation. Although final analysis continues, the Company estimates an increased capacity of 30 MWs for the unit as a result of these upgrades. Also, to address end-of-life for the unit, the generator stator, exciter and support systems were replaced. Other major work efforts during this outage included upper, lower, and volumetric reactor head inspections, replacement of the 2C reactor coolant pump motor, and overhauling the 2A service water pump.

Q. PLEASE DESCRIBE THE LOSS OF OFFSITE POWER EVENT AT CATAWBA.

A. The loss of offsite power event that occurred at Catawba in April 2012 was triggered by an electric fault on a cable associated with the 1D reactor coolant pump motor. This electric fault brought to light a protective relay scheme issue for the main generator, which resulted in four Unit 1 switchyard breakers opening unnecessarily. The issue with the protective relaying scheme was

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associated to a modification implemented in the prior year which was designed to provide additional frequency protection for the main generator. The Company completed repairs to the cable that faulted and corrected the relaying scheme issue for Unit 1, thereby ensuring the implementation of the relay scheme for the Unit 2 modification during the then current Unit 2 refueling and maintenance outage. Additionally, the Company verified that other stations were not vulnerable to the same situation and worked closely with the NRC's inspection team sent to review the situation and the corrective actions taken by the Company.

Importantly, when the unit automatically shut down, the emergency diesel generators started and supplied the power needed for essential equipment. The plant operators responded well to this extremely challenging event, as did the emergency organization that assembled to support them. Although the cause of the event was external to the station, it demonstrated the effectiveness of the station's protective systems and the ability of its operators to successfully manage the challenge.

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

A. The Company proposes to use a 92.84% capacity factor and believes that this capacity factor is reasonable for use in this proceeding based upon the operational history of DEC's nuclear units and the number of planned outage days scheduled during the billing period. This proposed percentage is reflected in the testimony and exhibits of Company Witness Smith and exceeds the five-year industry weighted average capacity factor of 89.79% for pressurized water reactors rated at and above 800 MWs as reported in the NERC Report representing the period of 2007 to 2011.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert J. ("Bob") Duncan, II. My business address is 526 South Church Street, Charlotte, North Carolina.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes, on March 6, 2013, I caused to be pre-filed with the Commission my direct testimony and an exhibit.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to support the Stipulation entered into by Duke Energy Carolinas, LLC ("DEC") and the Public Staff-North Carolina Utilities Commission ("Public Staff") filed on June 3, 2013 in this Docket, and also elaborate on the factual aspects of the nuclear outages that are addressed in the Stipulation.

Q. CAN YOU EXPLAIN THE FOREIGN MATERIAL EXCLUSION PORTION OF THE MCGUIRE UNIT 2 OUTAGE EXTENSION?

A. Yes. The McGuire Unit 2 Fall 2012 refueling and maintenance outage involved a significant scope of work, including replacement of the main generator stator, exciter and support systems, upgrade of the high pressure turbine and modification of the turbine generator support systems. These generator-turbine projects increase the capacity and improve the reliability of the unit. Managing foreign material exclusion ("FME") during an outage is highly challenging across the nuclear industry. Loose metallic objects in the generator have potentially high adverse consequences, including damage to the generator, reactor trips and personnel injury.

Prior to a planned outage such as this one, DEC develops a detailed schedule for the outage and for the major tasks to be performed, including sub-schedules for particular activities. The Company aggressively attempts to meet its best overall outage time for each outage and measures itself against that schedule. Additionally, DEC performs detailed self-critical analyses of each outage project and applies any lessons learned to ensure continuous improvement.

As noted in my direct testimony, rework due to foreign material contributed to the outage extension at McGuire. Specifically, on October 14, 2012, a day-shift craft millwright raised a concern that a 5/16" nut and lockwasher were missing from a 1.5-ton lever-operated hoist as the hoist was being removed from the Unit's Foreign Material Exclusion Zone ("FMEZ"). After extensive inspections, including removal of the generator's rotor, the missing parts were not located. The removal of the rotor was a decision that prolonged the outage, but also elevated plant equipment reliability and personnel safety over economic concerns.

Even though DEC and its contractor had implemented FME control efforts prior to the outage, and FME technicians inspected tools, including the hoist, prior to entry into the FMEZ, the extensive searches were reasonable and appropriate to assure that the missing parts were not in the generator.

The Company talked to the craft laborer and the FME technician who inspected the hoist prior to its entry into the FMEZ. The FME technician who inspected the tool prior to entry into the FMEZ stated that he performed the inspection and that he understood his training and the FME procedures regarding checking tools for loose parts; however, he could not specifically recall whether the nut and lockwasher were missing when he logged the hoist. The technician could not recall whether the nut and lockwasher were present or missing when the hoist entered the FMEZ. Therefore, DEC could not rule out the possibility that the parts were in the FMEZ. Only in hindsight, after the search and the uneventful startup and operation of the generator, do we know that the missing parts may well have been missing prior to the hoist's entry into the FMEZ

Q. CAN YOU EXPLAIN THE FRAME FOOT LOADING EVENT THAT LEAD TO A FURTHER EXTENSION OF THE OUTAGE?

A. Yes. The outage extension was also affected by problems encountered by a qualified contractor in leveling the frame footing (e.g., "frame foot loading" or "FFL") for the large electric main generator. The Company held the expectation that the leveling process, referred to as "shimming," could be achieved in the time scheduled for the task.

A new main turbine generator was installed during this outage, making extensive alignment necessary. Excessive vibration during generator startup would require the Unit to shut down until the source of the vibration, which in and of itself could cause equipment damage, could be identified and eliminated, so achieving an adequate alignment was a high priority. During outage planning, DEC and the contractor considered aligning the generator using either FFL or step shimming. Step shimming is simpler and more straightforward than FFL, but is much less accurate and can be inconclusive until generator startup. FFL produces a more accurate alignment but takes more time, is more complex, and requires more shim movements with a higher level of assurance of low vibration at startup. Before recent technological advances made FFL easier to perform, FFL was

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reserved for problematic alignments where excessive vibration had been observed in the main turbine generator.

Prior to the performance of the FFL at McGuire, DEC's subject matter experts performed quality reviews of the contractor's work packages for FFL, including the contractor's proprietary documents that relate to FFL technique. The Company also developed procedures to govern DEC's oversight of the contractor. Further, during execution efforts, DEC remained engaged asking questions of the contractor. Only after the contractor's 16th move was DEC aware that the contractor, and the contractor's technique, might not achieve desired results. At this point, DEC applied oversight resources to the contractor's conduct of the work. While monitoring the contractor's performance of FFL from moves 16 to 25, DEC noted several shortcomings in the contractor's performance and brought these to the contractor's attention. Following DEC's decision to intervene, DEC achieved an acceptable alignment in approximately one (1) day.

Consistent with nuclear industry practice, DEC and its vendor actively engaged in a self-critical post-outage critique process and developed a project plan to incorporate lessons learned and guide a similar scope of work performed during the McGuire Unit 1 spring 2013 refueling outage.

Q. CAN YOU EXPLAIN THE CATAWBA UNIT 1 FORCED OUTAGE AND UNIT 2 OUTAGE EXTENSION?

A. Yes. In May-June 2011, during Unit 1's 19th refueling and maintenance outage, DEC upgraded the generator protective relay system for the Unit. This system is designed to detect faults and other off-normal conditions affecting the switchyard or the main turbine generator. The turbine under-frequency protection design change was implemented to address equipment obsolescence and eliminate vulnerability in generator asset protection. The preexisting electro-mechanical relay scheme providing turbine under-frequency protection required upgrade and additional protection with digital components for the generator to protect against catastrophic damage if a ground fault should occur. In implementing the project, DEC developed specifications for a qualified vendor. The scope specification did not specifically call out with particularity a design input for the complex relay scheme and led to the omission of a "block" of a protection feature that isolates the Unit from the grid when the generator circuit breakers are open following a generator trip.

The outage in question began on April 4, 2012, when Unit 1 tripped off-line following a trip of the "1D" reactor coolant pump. Shortly thereafter, a portion of the generator protective relay system unexpectedly actuated when it sensed the instantaneous under-frequency condition of the Unit. This actuation opened the switchyard circuit breakers, thereby isolating Unit 1 from the transmission grid which supplies backup power to the Unit. This condition is referred to as a "Loss of Offsite Power" or "LOOP". The two emergency standby diesel generators automatically started as designed and powered the Unit until, five and a half hours later, offsite power was restored. Both the loss of reactor coolant pump flow and resultant reactor trip and the LOOP are events analyzed for safety as part of the plant's original license submittal, and the Unit is designed to safely shut down from such events.

The Company evaluated the situation and concluded that the 1D reactor coolant pump trip was caused by thermal damage to insulation on a reactor coolant pump motor power cable associated with a historic event in 2000, as well as degradation over time of the cable. The thermal damage was undetected and, in 2000, not readily detectable by cost-effective non-destructive testing methods then available. In April 2012, the cable "faulted to ground" at the location of the thermal damage. The faulted reactor coolant pump motor cable was replaced.

The old protection scheme used a series of relays and timers in a stepped protective relay scheme at various settings at different frequencies. Because the blocking scheme was not fully incorporated into the revised design, when the Unit's main generator tripped, the Unit was isolated from the grid when, as intended, the upgraded design should have blocked the isolation.

The Company utilized its highest level of risk management for the design change. Prior to the design change, DEC held numerous meetings with the vendor and reviewed the vendor's efforts throughout the design change process. During this review process, DEC spent hundreds of hours in design review, including review of computer coding but not source code, which is proprietary to the vendor. This source code contains algorithms for "accumulating" time related to relay functions. Based on programming coding reviewed by DEC, the accumulating function appeared to be designed correctly.

The relay programming is proprietary to the vendor and represents the vehicle for ensuring relay logic and schemes are executed as designed. In their review of the relay programming, Duke personnel reviewed the coding language to ensure time accumulation functions were present in each of the four zones of protection designed. The Duke personnel were not aware, however, that while the code variable programmed for Zones 1, 2, and 3 would work as designed to accumulate minutes, it would not work in Zone 4 to accumulate milliseconds. Because the source code was proprietary, the time segmentation of these accumulation algorithms was not disclosed to Duke personnel. The error in the accumulation algorithm in the protection scheme is the source of the design error and was carried forward into the accept testing.

Q. IN LIGHT OF THE COMPANY'S EXPLANATION OF THE MCGUIRE AND CATAWBA OUTAGES, WHY DID DEC ENTER IN TO THE STIPULATION?

A. As explained in the testimony of Public Staff witness Ellis, the Public Staff's investigation into these outage extensions resulted in it concluding that certain nuclear outage time could have been avoided and that, therefore, the Company should forego recovery of those expenses. In my supplemental testimony, I have explained DEC's analysis of the Catawba and McGuire outages as they occurred in real time from DEC's perspective, and for the reasons set forth above, the Company disagrees with the Public Staff's conclusions on certain portions of those outages.

Both parties, however, recognized that the causes and lengths of nuclear outages, like nuclear operations in general, are complex and difficult to explain and, as alluded to in Public Staff witness Ellis' testimony, reasonable persons with knowledge and experience in nuclear operations can disagree as to the drivers of specific outage delays. As a result, the Parties agreed that the Company would agree to a stipulated adjustment of $5.3 million on a North Carolina retail basis, including interest to resolve the matter. In agreeing to this adjustment, however, DEC does not admit that any of the outage time in question was the result of imprudence, unreasonableness, inefficient management, or uneconomic operations of its nuclear generation fleet. Additionally, the capacity factors for McGuire Nuclear Station and Catawba Nuclear Station both exceeded the NERC five-year average nuclear capacity factor on a standalone basis. The Company also believes it is key to place each event in its proper context and focus attention on the facts and circumstances as they existed at the time of each incident without the benefit of hindsight, including key decisions leading up to these events.

Q. DOES THIS CONLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

(Whereupon, Confidential Duncan
Exhibit Number 1 was identified
as premarked.)

BY MR. FRANKLIN:

Q Mr. Duncan, did you prepare a summary of your testimony today?

A Yes, I did.

Q Would you please read that summary to the Commission?

A Yes. (Summary read into the record.)

Robert J. Duncan, II's Direct and Supplemental Testimony Summary

Docket No. E-7, Sub 1033

The purpose of my testimony is to describe and discuss the performance of McGuire and Catawba nuclear stations, as well as DEC's Oconee Nuclear Station during the test period of January 1, 2012 through December 31, 2012. I also discuss the nuclear capacity factor being proposed by DEC and used in this proceeding for determining the fuel factor to be reflected in rates during the billing period of September 1, 2013 through August 31, 2014.

The Company's nuclear generation portfolio consists of approximately 5,200 megawatts of generating capacity. The Company's nuclear fleet consists of three generating stations and a total of seven units.

Overall, the Company's nuclear stations operated well during 2012, and supplied 62% of the power used by its customers in the test period. The seven nuclear units operated at a system average capacity factor of 91.85%, which exceeded the NERC five-year capacity factor average of 89.79% for pressurized water reactors. The 89.79% capacity factor represents an average of comparable units, which are pressurized water reactors on a weighted basis with capacity ratings at and above 800 MWs. The capacity factor at McGuire Unit 1 was 104.67%, an annual record for the unit. Overall, the Company's average nuclear capacity factor has been above 90% for 13 consecutive years. The performance results for the test period support DEC's continued commitment to achieving high performance without compromising safety and reliability,

There were five refueling and maintenance outages during the test period and additional time was required during three of these outages to complete activities needed for on-line reliability.

The Company proposes to use a 92.84% capacity factor and believes that this capacity factor is reasonable for use in this proceeding based upon the operational history of DEC's nuclear units and the number of planned outage days scheduled during the billing period.

As explained in the testimony of Public Staff witness Ellis, the Public Staff raised some concerns about certain of the Company's nuclear outages. In my supplemental testimony, I have explained DEC's perspective on these outages, and that the Company disagrees with the Public Staff's position. Both parties, however, recognized that the causes and lengths of nuclear outages, like nuclear operations in general, are complex and difficult to explain and, as alluded to in Public Staff witness Ellis' testimony, reasonable persons with knowledge and experience in nuclear operations can disagree as to the drivers of specific outage delays. As a result, the Parties agreed that the Company would agree to a stipulated adjustment of $5.3 million on a North Carolina retail basis, including interest to resolve the matter.

This concludes my testimony summary.

MR. FRANKLIN: Chairman Finley, if I might add one note for the record before making our witnesses available for cross examination, that the Commission is aware in past fuel dockets North Carolina Sustainable Energy Association has asked questions of DEC regarding natural gas hedging practices. To that end, DEC's counsel and NCSEA's counsel have discussed, and we've committed that no later than six months as of today's date, the Company will file an updated Fuel Procurement Practices Report in Docket Number E-100, Sub 478, that will include DEC's proposed natural gas hedging strategy, so I wanted to get that on the record. But with that said, the Company's witnesses are now available for cross examination.

CHAIRMAN FINLEY: All right. Mr. Youth, do you have questions?

MR. YOUTH: No.

CHAIRMAN FINLEY: Mr. Runkle?

MR. RUNKLE: No, Your Honor.

MS. DOWNEY: No.

CHAIRMAN FINLEY: Does the Commission have questions? Commissioner Culpepper.

EXAMINATION BY COMMISSIONER CULPEPPER:

Q I guess this is for Mr. Weintraub, and this is following up on counsel's discussions about the hedging strategy of the Company, is that proprietary information? Is that something we can talk about in an open hearing?

A (Mr. Weintraub) Yes, it is.

Q Proprietary.

A No, it isn't. We can discuss it in an opening hearing. Currently, DEC does not have a hedging strategy. We would welcome discussing it.

Q Okay. Well, I was noticing in your summary here, getting down to the bottom of page 1, you say, "DEC does not currently employ a hedging strategy to fix prices on a portion of its projected natural gas usage." I read that to mean that you have some sort of strategy in place and you hedge on part of it, but you don't hedge on the rest of it. Am I wrong in reading it that way?

A No, sir. What my testimony is alluding to is when you have a natural gas hedging strategy, you're really going to do it for just a portion of your gas burn because gas is volatile in terms of how much you're actually going to burn, so a hedging strategy would, hypothetically picking a number, you'd want to hedge, say, 50 percent of your projected burn, and that's where your hedging strategy would be employed, and the remainder percent would be you'd buy a spot and not have a hedging program for that burn percent.

Q Is that what's going on right now, 50-50?

A Right now there's zero, so DEC does not have any hedging strategy for their natural gas. With their combined cycles just coming on, we've just reached, I would say, a critical mass enough that we can now discuss a hedging strategy because there's enough gas burn for DEC as the combined cycle facilities at Buck and Dan River are now online and operational.

COMMISSIONER CULPEPPER: That's it.

EXAMINATION BY CHAIRMAN FINLEY:

Q Mr. Duncan, how does one have a capacity factor in excess of 100 percent?

A (Mr. Duncan) It's based on a number that's associated with the MDC, so the maximum dependable capacity. Numbers above the maximum dependable capacity allow you to get a capacity factor over 100 percent.

Q How far above 100 percent can we go?

A It's based on the MDC that's set for the plant, as well as the economic -- or excuse me -- the environmental conditions that occur during the year. So a very hot summer would knock that generation production down in the summer because of the heat rejection capability and have a lower capacity factor.

Q That's perfectly clear to me.

CHAIRMAN FINLEY: Are there any questions on the Commission's questions?

(No response.)

CHAIRMAN FINLEY: All right. Thank you gentlemen and ladies.

(Witnesses excused.)

MR. FRANKLIN: Chairman Finley, just as a matter of housekeeping, we move that Mr. Weintraub's and Mr. Duncan's exhibits, as well as Ms. Smith's revised exhibits, be admitted into evidence, and we also move that the previously filed testimony of Witnesses Culp and Miller be copied into the record, and Mr. Culp's exhibits be received as premarked as well.

CHAIRMAN FINLEY: All right. The direct prefiled testimony of Witnesses Culp and Miller -- did they have exhibits?

MR. FRANKLIN: Mr. Culp has two exhibits.

CHAIRMAN FINLEY: Their prefiled testimony shall be copied into the record as though given orally from the stand, and Mr. Culp's exhibits shall be marked and received, and the exhibits of the three panel witnesses shall be received into evidence.

(Whereupon, the prefiled testimony of David C. Culp and Joseph A. Miller was copied into the record as if given orally from the stand.)

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David C. Culp 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 Carolinas, LLC ("DEC" or the "Company") and Progress Energy Carolinas, Inc. ("PEC").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEC?

A. I am responsible for nuclear fuel procurement, spent fuel management, reactor core design, nuclear safety analysis, and reload analysis methods for the nuclear units owned and operated by DEC and Progress Energy Inc.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of South Carolina with a Bachelor of Science degree in mechanical engineering and a Master's degree in business administration. I began my career with the Company in 1986 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 in 1995. Beginning in 1999, I incrementally assumed responsibility for spent nuclear fuel management, nuclear fuel mechanical and thermal hydraulic design, and reactor core design. In 2003, I was named vice president of Claiborne Energy Services – a partner in the

Louisiana Energy Services venture to license, construct, and operate a new uranium enrichment plant in the United States. I assumed my current role in 2011.

I have served as Chairman of the World Nuclear Fuel Market's Board of Governors, an organization that promotes efficiencies in the nuclear fuel markets. I have also served as Chairman of the Ad Hoc Utilities Group ("AHUG"), an association that promotes free trade in nuclear fuel, and Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use. I am a registered professional engineer in the states of North Carolina and South Carolina.

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

A. The purpose of my testimony is to (1) provide information regarding DEC's nuclear fuel purchasing practices, (2) provide costs for the January 1, 2012 through December 31, 2012 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2013 through August 31, 2014 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 Culp Exhibit 1, which is a Graphical Representation of the

Nuclear Fuel Cycle, and Culp Exhibit 2, which sets forth the Company's Nuclear Fuel Procurement Practices.

Q. MR. CULP, 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 Culp 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% U-235 and 99.3% U-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. The two commercially available enrichment processes, gaseous diffusion and gas centrifuge, first heat 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 UF6 is enriched to the desired level, it is converted to uranium dioxide ("UO_2") powder and formed into pellets. This process and subsequent steps of inserting the fuel pellets into fuel rods and bundling the rods into fuel assemblies for use in nuclear reactors is referred to as fabrication.

Q. **PLEASE PROVIDE A SUMMARY OF DEC'S NUCLEAR FUEL PROCUREMENT PRACTICES.**

A. As set forth in Culp Exhibit 2, DEC's nuclear fuel procurement practices involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of spot and long-term contracts from diverse sources of supply, assessing spot market opportunities, 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. The typical initial delivery under new long-term contracts has grown to several years after contract execution because many proven, reliable producers have sold their near-term capacity. For this reason, DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Q. WHAT CHANGES HAVE OCCURRED IN THE UNIT COST OF THE VARIOUS STAGES OF NUCLEAR FUEL DURING THE TEST PERIOD?

A. During the test period, the published long-term market price for uranium concentrates was in the range of $56.00/lb to $61.50/lb. During this same period, the published spot market price, which is referenced in a segment of long-term contracts in order to establish delivery price, ranged from a low of $42.00/lb to a high of $52.00/lb. The impact of the spot market volatility on

DEC was mitigated by the portfolio of supply contracts negotiated in prior years which use a mixture of pricing mechanisms. The Company's portfolio of diversified contract pricing yielded an average unit cost of $47.13/lb for uranium concentrates during the test period.

Industry consultants believe market prices need to increase from current levels in order to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements. As a portion of DEC's existing supply contracts expire each year, they will be replaced by contracts that are anticipated to contain higher delivery prices.

During the test period, the published long-term market price for enrichment services was in the range of $134.00/Separative Work Unit ("SWU") to $148.00/SWU. One hundred percent of DEC's enrichment purchases during the test period were delivered under long-term contracts negotiated at market prices prior to the test period. This mitigated the impact of price uncertainty on DEC during the test period. The average unit cost of DEC's purchases of enrichment services during the test period was $117.19/SWU. As existing enrichment contracts in DEC's portfolio expire, they will be replaced with contracts that are anticipated to contain higher delivery prices.

Fabrication and conversion prices generally trended upward during the test period. These costs, however, have a limited impact on the overall fuel expense rate given that the dollar amounts for these purchases represent a substantially smaller percentage – 14% and 4%, respectively, for the fuel batches recently loaded into DEC's reactors – of the Company's total direct fuel cost relative to uranium concentrates or enrichment, which are 43% and 39%, respectively.

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

A. The Company anticipates an increase in nuclear fuel expense through the next billing period. Because fuel is typically expensed over two to three operating cycles – roughly three to five years – DEC's nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period, as well as prior periods. A portion of the fuel residing in the reactors during the billing period will have been obtained under contracts negotiated prior to the recent market price increases. Newer contracts reflecting increasing price trends, however, are now contributing to a portion of the uranium, enrichment, and fabrication costs reflected in the total fuel expense.

As a result of the above noted changes, the average fuel expense is expected to increase from 0.574 cents per kilowatt hour ("kWh") incurred in the test period, to approximately 0.676 cents per kWh in the billing period. As fuel with a low cost basis is discharged from the reactor and lower priced legacy contracts continue to expire, nuclear fuel expense is anticipated to experience further increases in the future.

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

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

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 the Company'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 TESTIMONY?**

A. Yes, it does.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph A. Miller, Jr. and 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 currently Director of Strategic Engineering for Duke Energy Business Services, LLC ("DEBS"). DEBS is a service company subsidiary of Duke Energy Corporation ("Duke Energy"), which provides services to Duke Energy and its subsidiaries, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas", "DEC" or "the Company"). Prior to the merger between Duke Energy and Progress Energy, Inc., (the "Merger"), I served as General Manager of Analytical and Investments Engineering for DEBS.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Purdue University with a Bachelor of Science degree in mechanical engineering. I also completed twelve post graduate level courses in Business Administration at Indiana State University. My career began with Duke Energy (d/b/a Public Service of Indiana) in 1991 as a staff engineer at Duke Energy Indiana's Cayuga Steam Station. Since that time, I have held various roles of increasing responsibility in the generation engineering, maintenance, and operations areas, including the role of station manager, first at Duke Energy Kentucky's East Bend Steam Station, followed by Duke Energy Ohio's Zimmer Steam Station. I was named General Manager of Analytical and

Investments Engineering in 2010, and was named to my current role following the Merger.

Q. **WHAT WERE YOUR DUTIES PRIOR TO THE MERGER AND WHAT ARE YOUR DUTIES AS DIRECTOR OF STRATEGIC ENGINEERING?**

A. Prior to the Merger, my responsibilities included leading the groups responsible for project controls and engineering analysis of capital projects for the Company's generation fleet of nuclear, fossil, and hydroelectric ("hydro" and collectively, "fossil/hydro") facilities. My responsibilities also included, and continue to include, environmental compliance planning and strategy, fuel flexibility, assessment of new technology developments, and analysis of plant retirements and new fossil generation.

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

A. No. I did file testimony before this Commission, however, in the Company's 2012 annual fuel proceeding in Docket No. E-7, Sub 1002 ("2012 Fuel Filing"), and have filed testimony in the Company's recent base rate adjustment filing in Docket No. E-7, Sub 1026. I have also testified on behalf of Duke Energy in proceedings before other state commissions, most recently in January 2013.

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

A. The purpose of my testimony is to (1) describe the Company's generation portfolio and changes made since the 2012 Fuel Filing, as well as those expected in the near term, (2) discuss the performance of the Company's fossil/hydro facilities during the test period of January 1, 2012 through December 31, 2012 (the "test period"), and (3) provide information on significant outages that occurred during the test period.

Q. PLEASE DESCRIBE THE COMPANY'S FOSSIL/HYDRO GENERATION PORTFOLIO.

A. The Company's fossil/hydro generation portfolio as of December 31, 2012 consists of approximately 15,000 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	7,882 MWs
Hydro -	3,229 MWs
Combustion Turbines -	2,769 MWs
Combined Cycle Turbines -	1,240 MWs

The coal-fired assets consist of seven generating stations and a total of 22 units. The Company has 13 units that are larger coal-fired facilities with a total of 6,802 MWs of capacity. Each of these units is equipped with emission control equipment, including selective catalytic or selective non-catalytic reduction ("SCR" or "SNCR") equipment for removing nitrogen oxides ("NOx"), and flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"). The remaining nine coal-fired units – considered to be intermediate or cycling units – include six that are also equipped with SNCRs. In addition, all 22 coal-fired units are equipped with low NOx burners.

The Company has a total of 31 simple cycle combustion turbine ("CT") units, of which 29 are considered the larger group providing approximately 2,687 MWs of capacity. These 29 units are located at Lincoln, Mill Creek and Rockingham Stations, and are equipped with water injection systems that reduce NOx and/or have low NOx burner equipment in use. The Lee CT facility includes two units with a total capacity of 82 MWs equipped with fast-start ability in support of the Company's Oconee Nuclear Station. The 1,240 MWs shown earlier as "combined cycle turbines" ("CC") represent the Buck CC and Dan River CC facilities that began commercial operation in late 2011 and late 2012, respectively. These facilities are equipped with the latest technology for emission control including SCRs, low NOx burners, and carbon monoxide/volatile organic compounds catalysts. The Company's hydro fleet includes two pumped storage hydro facilities that provide a total capacity of 2,140 MWs along with conventional hydro assets consisting of 82 units providing approximately 1,089 MWs of capacity.

Q. **WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO PORTFOLIO SINCE THE COMPANY'S 2012 FUEL FILING?**

A. Changes within the portfolio include the addition of 1,445 MWs of new generation when Dan River CC and Cliffside Steam Station ("Cliffside") Unit 6 were declared available for commercial operation in December 2012. The Company received certificates of public convenience and necessity ("CPCN") from the Commission to construct Dan River CC and Cliffside Unit 6 in Docket No. E-7, Subs 832 and 790, respectively. The Company retired coal-fired Units

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1 through 4 at Cliffside, 3 and 4 at Buck Steam Station ("Buck"), and 1 through 3 at Dan River Steam Station ("Dan River"). This total reduction of 587 MWs of coal-fired capacity moved DEC forward to meeting requirements set forth in the CPCN and the Air Permit, issued by the North Carolina Department of Environment & Natural Resources, Division of Air Quality, for Cliffside Unit 6. Lastly, due to age and obsolescence, the Company retired older CTs at Buck, Buzzard Roost, Dan River, and Riverbend Stations for a reduction of 350 MWs.

Q. **ARE OTHER CAPACITY CHANGES EXPECTED WITHIN THE FOSSIL/HYDRO PORTFOLIO FOR THE NEAR FUTURE?**

A. Yes. As part of the fleet modernization program, the Company will retire the remaining two units at Buck, Units 5 and 6 (256 MWs), along with Riverbend Steam Station, Units 4 through 7 (454 MWs) by April 1, 2013. These assets have served customers well for multiple decades and, at 58 to 60 years old, are at the end of their useful lives. The Company had planned to retire these units in April 2015, but has operated them infrequently in recent years and would operate them even less due to low natural gas prices and new generation resources that are more efficient. Additionally, the Company had already agreed to retire these units in progressive fashion under the Cliffside Unit 6 air permit and Merger agreements.

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

A. The primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC's customers. The

Company achieves this objective by focusing on a number of key areas. 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.

Like safety, environmental compliance is a "first principle" and DEC works very hard to achieve high level results. Duke Energy Carolinas achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers. Equipment inspection and maintenance outages are scheduled during the spring and fall months when electricity demand is reduced due to weather conditions. These outages are well-planned and executed with the primary purpose of preparing the unit for reliable operation until the next planned outage.

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

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the test period, the average heat rate for DEC's coal fleet was 9,539 Btu/kWh. The Company's largest units – those with the highest usage rates – achieved an average heat rate of 9,497 Btu/kWh for the test period. In operating performance data for 2011, published in the December 2012 issue of *Electric Light and Power* magazine, the Company's Belews Creek Steam Station ("Belews Creek") and Marshall Steam Station ("Marshall") ranked as the country's fourth and eighth most energy efficient coal-fired generators, with heat rates of 9,210 and 9,480 Btu/kWh, respectively. These results compare favorably to the average heat rate of 10,450 Btu/kWh for the North American coal generators. For the test period, the Belews Creek units provided the majority (50.0%) of coal-fired generation for the Company, with the Marshall units providing the second highest percentage (34.4%).

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

A. The Company's system generation totaled 90,527,227 MW hours ("MWHs") for the test period. The fossil/hydro fleet provided 34,071,818 MWHs, or approximately 38% of the total generation. The breakdown includes a 31% contribution from the coal-fired stations, approximately 1% contribution each for the CTs and hydro facilities, and approximately 5% from the CC operations.

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

A. The Company's generating units operated efficiently and reliably during the test period. The Company uses key measures to evaluate the operational performance of generating facilities: (1) equivalent availability factor; and (2) capacity factor. Equivalent availability factor refers to the percent of a given time period a facility was available to operate at full power, if needed. Equivalent availability is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (*i.e.*, forced) outage time. Capacity factor 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. Capacity factor is affected by the dispatch of the unit to serve customer needs. Further, the performance reporting is categorized in order to appropriately reflect operational characteristics -- large coal-fired facilities, which have a higher usage rate and are the most cost effective generators within the generator type group.

The Company's larger coal-fired units achieved results of 88.5% equivalent availability factor and 50.8% capacity factor over the test period. During the 2012 peak summer season (e.g., June through August 2012), these larger units achieved results of 96.2% equivalent availability factor and 65.5% capacity factor. The Company's nine cycling coal-fired units achieved results of 98.5% equivalent availability factor and 5.3% capacity factor over the review period, and during the 2012 summer peak months they achieved results of 98.1% equivalent availability and a capacity factor of 11.5%. The low capacity factors for these coal-fired units are a result of their minimal operation due to the Company running its natural gas units more frequently to take advantage of low prices and as a result of the Joint Dispatch Agreement, and are a direct example of the impact that the low pricing of shale gas, as described in Company Witness Weintraub's testimony, has had on many utilities' generation dispatch orders.

On a total coal-fired fleet basis, the capacity factor was 43.9% for the review period and 57.3% during the 2012 summer peak months. Overall, the coal-fired units achieved a fleet-wide availability factor of 90.0% for the review period, and 96.5% during the 2012 summer peak months. These results compare favorably with the most recently published North American Electric Reliability Council ("NERC") average equivalent availability results for all North American coal plants of 83.5%. The results, included in the NERC Generating Availability Report ("NERC Report"), represent the period 2007 through 2011. Typically, the Company obtains this data from NERC's Generating Unit Statistical Brochure ("NERC Brochure"). The most recent NERC Brochure, however, has not yet been published, and as a result, the Company computed this data from the NERC Report.

The Company's CTs located at Lincoln, Mill Creek, Rockingham, and Lee Stations were available as needed in this time period, with a 99.2% starting reliability, outperforming the average of 97.4% reported by NERC in the above-referenced report. The Buck CC facility reported a capacity factor of 76.5%, which is above the NERC reported average of 40.4%. With an overall availability factor of 93.4%, the hydroelectric fleet had outstanding operational performance during the review period, and also exceeded the NERC reported average availability factor of 85.2%.

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

A. In general, planned maintenance outages for all fossil and larger hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most of these units had at least one small planned outage during this test period to inspect and maintain plant equipment. Five of the 22 coal-fired units had planned outages of three weeks or more. In the spring of 2012, maintenance outages included Belews Creek Unit 2, which involved significant work on boiler waterwall replacement and relining FGD absorber structures along with inspections on the turbine and generator. Outage work on Marshall Unit 4 included FGD maintenance, boiler waterwall work, piping and valve installations for the desuperheater, and replacement of preheater baskets, along with maintenance on mills/feeders, precipitators and flyash systems. In the fall of 2012, Allen Units 1, 2 and 5 had outages for FGD absorber maintenance and warranty work along with air preheater basket replacement for Unit 5. Significant work during these outages included installation of a potential adjustment protection system for the absorber reaction tank, battery bank replacement, and the rebuild of multiple valves.

Combustion turbine outages included Lincoln Units 11 and 12 in the spring which involved hot gas path inspections along with annual maintenance activities. A borescope inspection and fuel nozzle replacement was also performed on Unit 12. Outages for Mill Creek Units 5 and 6 were completed to perform combustion and generator inspections, and a hot gas path inspection on Unit 6 in addition to annual maintenance activities. Also, in the spring, a planned outage for Rockingham Unit 3 was conducted for a hot gas path inspection as well as a generator inspection and annual maintenance activities. In the fall, outages occurred for Lincoln Units 3 and 4 that involved generator inspections along with annual maintenance activities.

Outages began for Rockingham Units 1 and 3 for borescope inspections. The inspections revealed cracks and material loss in transition pieces with downstream damage to turbine blades and vanes. The Company opted to take Units 2 and 4, which are equipped with the same style and vintage pieces, offline and perform borescope inspections. The inspections on Units 2 and 4 revealed suspect areas in the transition pieces for Unit 2 and several cracked transition pieces but without material loss for Unit 4. Purchase of new components -- Units 1 and 3 had sustained in-service damage to certain components that were not repairable -- reduced the lead-time on repairs, and the units were returned to service late in December 2012. The components for Units 2 and 3 were repairable, which reduces the costs but increases the lead-time; these units are scheduled to return to service in late March 2013.

Q. PLEASE DESCRIBE THE ROCKINGHAM UNIT 5 OUTAGE FROM THE PRIOR YEAR THAT EXTENDED INTO THE TEST PERIOD.

A. In October 2011, a planned annual borescope inspection on Rockingham Unit 5 revealed damage to turbine blades. After preliminary evaluation of the damage, the unit was placed in an outage. The finding of the turbine blade failure analysis was the failure of one or more row 1 turbine blade tip caps which caused domestic object damage to the row 1 through row 4 turbine blades and turbine vanes, which were damaged to the extent of needing extensive repairs. The lead time for the repairs was 16 weeks with a ship date of April 2, 2012 from Siemens Energy's Houston Texas repair center.

Unit 5 had been experiencing unexpectedly higher than usual NOx emissions since it was returned to service from a hot gas path inspection in the spring of 2010, making compliance with NOx emissions limits difficult at full load. Several attempts had been made to reduce the NOx emissions including controls tuning, fuel nozzle replacements, and change out of combustor baskets with Siemens' extra thick thermal barrier coating baskets. Although some improvements were achieved, DEC took the opportunity afforded by the forced outage to make improvements to fuel nozzles that have restored NOx performance. Following return to service in late May 2012, Unit 5 achieved an equivalent availability factor of 96.2% for the remainder of the test period.

Q. HOW DOES THE COMPANY ENSURE EMISSION REDUCTIONS FOR ENVIRONMENTAL COMPLIANCE?

A. As noted above, DEC 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 NO_x and SO_2 emissions. The SCR technology that the Company currently operates uses ammonia or, in the case of Marshall Unit 3, urea, which is converted to ammonia for NO_x removal.

The SNCR technology injects urea into the boiler for NO_x removal and the scrubber technology employed by the Company uses crushed limestone for SO_2 removal. Dibasic acid can also be used with the scrubber technology for additional SO_2 removal. SCR equipment is also an integral part of the design of the Buck and Dan River CC Stations. Aqueous ammonia (19% solution of NH_3) is introduced for NO_x removal.

Overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emission reduction required. As a result, the Company uses chemicals such as the aforementioned limestone, ammonia, urea, and dibasic acid, as well as chemicals such as magnesium hydroxide and calcium carbonate, which are used in order to mitigate increased sulfur trioxide ("SO_3") emissions due to consumption of higher sulfur coals pursuant to DEC's fuel flexibility efforts as described by Company Witness Weintraub. The Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. The goal is to effectively comply with emission regulations and provide the most efficient total-cost solution for operation of the unit.

For the test period, the Company spent a total of \$25 million on chemicals used to reduce emissions and has included \$42 million for the proposed fuel factor. The proposed costs show an increase most notably to support new generation resources at Cliffside and Dan River as noted earlier.

Q. **DOES THAT CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes, it does.

(Whereupon, Culp Exhibits 1 and 2
were identified as premarked and
admitted into evidence.)

(Whereupon, Weintraub Exhibits 1 and
2, Smith Exhibits 1 through 6 and
Smith Revised Exhibits 1 through 6
were admitted into evidence.)

(Whereupon, Confidential Duncan
Exhibit Number 1 was admitted into
evidence and filed under seal.)

MR. FRANKLIN: That concludes Duke Energy's case.

CHAIRMAN FINLEY: All right. Who's next? Ms. Downey.

MS. DOWNEY: Mr. Chairman, as an initial matter, we would note for the record that the Public Staff was unable to identify any public witnesses that wish to testify.

CHAIRMAN FINLEY: Very well.

MS. DOWNEY: And with the Chairman's permission, we would like to call our witnesses as a panel as well.

CHAIRMAN FINLEY: Without objection, the Public Staff may call its witnesses as a panel.

MS. DOWNEY: We would call Kennie Ellis, Jim Hoard and Randy Edwards to the stand.

KENNIE D. ELLIS; Being first duly sworn,
testified as follows:

JAMES G. HOARD; Being first duly sworn,
testified as follows:

RANDY T. EDWARDS; Being first duly sworn,
testified as follows:

MS. DOWNEY: I'll start with Mr. Edwards.

DIRECT EXAMINATION BY MS. DOWNEY:

Q Mr. Edwards, would you please state your name, business address and present position.

A (Mr. Edwards) My name is Randy T. Edwards. My business address is 430 North Salisbury Street, Raleigh, NC. I am a Staff Accountant with the Accounting Division of the Public Staff, North Carolina Utilities Commission.

Q Did you prepare and caused to be filed on June 3, 2013 testimony in this case consisting of 11 pages and an appendix?

A I did.

Q Do you have any corrections or changes to that testimony at this time?

A I do not.

Q If the same questions were asked of you today, would your answers be the same?

A Yes.

MS. DOWNEY: Mr. Chairman, I'd move that the direct testimony of the witness be copied into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Edwards' direct prefiled testimony filed on June 3, 2013, consisting of 11 pages shall be copied into the record as though given orally from the stand.

(Whereupon, the prefiled testimony of Randy T. Edwards and Appendix A was copied into the record as if given orally from the stand.)

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Clerk's Office
N.C. Utilities Commission

DUKE ENERGY CAROLINAS, LLC
DOCKET NO. E-7, SUB 1033

TESTIMONY OF RANDY T. EDWARDS
ON BEHALF OF THE PUBLIC STAFF

NORTH CAROLINA UTILITIES COMMISSION

June 3, 2013

Q. WILL YOU STATE FOR THE RECORD YOUR NAME, ADDRESS, AND PRESENT POSITION?

A. My name is Randy T. Edwards. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am a Staff Accountant with the Accounting Division of the Public Staff – North Carolina Utilities Commission.

Q. HOW LONG HAVE YOU BEEN EMPLOYED BY THE PUBLIC STAFF?

A. I have been employed by the Public Staff since October 1998.

Q. WHAT ARE YOUR DUTIES?

A. I am responsible for the performance of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings.

Q. WOULD YOU BRIEFLY STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE?

A. A summary of my education and experience is set forth in Appendix A to my testimony.

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

A. The purpose of my testimony is to present the results of the Public Staff's investigation of the Experience Modification Factor (EMF) billing factors proposed by Duke Energy Carolinas, LLC (DEC or the Company), in this proceeding. The EMF billing factors are utilized to "true-up" the recovery of fuel and fuel-related costs incurred during the test year. DEC's test year in this fuel and fuel-related cost proceeding is the twelve months ended December 31, 2012.

Q. DID DEC INCLUDE IN THE EMF CALCULATION ACTUAL FUEL AND FUEL-RELATED COSTS AND REVENUES INCURRRED FOR THE PERIOD JANUARY THROUGH APRIL 2013, AS PERMITTED BY G.S. 62-133.2(d)?

A. No. The Company notified the Public Staff that it has decided not to file an update to include January through April 2013 fuel and fuel-related costs and revenues in this proceeding.

Q. WHAT EMF INCREMENT/(DECREMENT) BILLING FACTORS IS DEC REQUESTING IN THIS PROCEEDING?

A. In its application filed on March 7, 2013, the Company proposed an overall EMF decrement billing factor of (0.0852) ¢/kWh based on its calculated and reported North Carolina retail fuel and fuel-related cost overrecovery for the test year of $47,306,484. This factor was calculated by dividing the fuel and fuel-related cost overrecovery by DEC's test year North Carolina retail sales, adjusted for customer growth and weather, of 55,534,610 MWH. The Company's proposed EMF decrement billing factors for each North Carolina retail customer class, excluding gross receipts tax (GRT) and the North Carolina regulatory fee, are as follows:

Customer Class	EMF Decrement Factors
Residential	(0.0382) ¢/kWh
Commercial	(0.1099) ¢/kWh
Industrial	(0.1216) ¢/kWh

These EMF decrement billing factors are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost overrecoveries for the test year of $8,086,940 for the residential customer class, $24,292,108 for the commercial customer class, and $14,927,436 for the industrial customer class. The factors were calculated by dividing the fuel and fuel-related cost overrecoveries by DEC's test year North Carolina retail sales, adjusted for customer growth and weather, of 21,143,695 MWH for the residential customer class, 22,112,646 MWH for the commercial customer class, and 12,278,269 MWH for the industrial customer class. The Company's proposed EMF decrement billing factor calculations are presented on Company witness Ms. Smith's Exhibit 3, pages 1 through 4.

Q. DID THE COMPANY INCLUDE ANY ADJUSTMENTS IN THE PROPOSED EMF DECREMENT BILLING FACTORS?

A. Yes. As shown on Smith Exhibit 3, pages 1 through 4, the EMF decrement billing factors include a correction for renewable purchased power and an adjustment for merger savings to be shared with Progress Energy Carolinas, Inc., now Duke Energy Progress, Inc. These adjustments are discussed on pages 12 and 13 of Ms. Smith's direct testimony.

Q. IS INTEREST APPLICABLE TO THE TEST YEAR OVERRECOVERIES?

A. Yes. Pursuant to G.S. 62-130(e) and Commission Rule R8-55(d)(6), any overcollection of fuel and fuel-related costs to be refunded to DEC's customers through operation of the EMF rider must include interest, at such rate as the Commission may determine to be just and reasonable, not to exceed ten percent (10%) per annum.

In the Company's application filed on March 7, 2013, DEC proposed an overall EMF interest decrement billing factor of (0.0142) ¢/kWh based on $7,884,411 interest calculated on the overall $47,306,484 overrecovery of fuel and fuel-related costs. This factor was calculated by dividing the $7,884,411 by DEC's test year North Carolina retail sales, adjusted for customer growth and weather, of 55,534,610 MWH. The Company's proposed EMF interest amounts for the customer classes are: $1,347,823 for the residential customer class, $4,048,683 for the commercial customer class, and $2,487,905 for the industrial customer class. These interest amounts were divided by Duke's test year North Carolina retail sales, adjusted for customer growth and weather, of 21,143,695 MWH for the residential customer class, 22,112,646 MWH for the commercial customer class, and 12,278,269 MWH for the industrial customer class resulting in the following EMF interest decrement billing factors:

Customer Class	EMF Interest Decrement Factors
Residential	(0.0064) ¢/kWh
Commercial	(0.0183) ¢/kWh
Industrial	(0.0203) ¢/kWh

The EMF interest decrement billing factor calculations are also presented on Ms. Smith's Exhibit 3, pages 1 through 4.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S INVESTIGATION OF THE EMF DECREMENT BILLING FACTORS.

A. The Public Staff's investigation of the proposed EMF decrement billing factors consisted of procedures intended to enable the Public Staff to evaluate whether the Company properly determined its per books fuel and fuel-related costs and revenues during the test period. These procedures included a review of prior Commission orders, the Company's application in this proceeding, Monthly Fuel Reports filed with the Commission, and other Company data provided to the Public Staff. Additionally, the investigation included review of certain specific types of expenditures impacting the Company's test year fuel and fuel-related costs, including nuclear fuel disposal costs and payments to non-utility generators. Also, the Public Staff's investigation included review of source documentation of fuel costs for certain selected Company generation resources.

Performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests, as well as site visits to the Company's corporate offices.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE COMPANY'S PROPOSED EMF DECREMENT BILLING FACTORS?

A. Yes. Pursuant to the Joint Agreement and Stipulation of Settlement (Stipulation) between the Public Staff and the Company, I have increased the Company's proposed North Carolina retail test year overrecovery amount by $4,542,857. This amount represents replacement power costs the Company incurred related to the performance of its nuclear plants during the test year. Public Staff witness Ellis discusses the reasons for the adjustment in his testimony.

Q. ARE THERE ANY OTHER ADUSTMENTS THAT SHOULD BE MADE THAT IMPACT THE COMPANY'S PROPOSED EMF DECREMENT BILLING FACTORS?

A. Yes. The Public Staff has recently learned that the Company's North Carolina retail fuel and fuel-related costs should be increased by $294,198 for purchases from qualifying facilities. According to the Company, $294,198 of fuel and fuel-related costs was inadvertently omitted from the fuel and fuel-related costs included in this proceeding when DEC filed its March 6, 2013 application. This adjustment is discussed in the Stipulation.

It should be noted that the Public Staff agreed to allow the Company to include the $294,198 in this proceeding because it was incurred in the fuel proceeding test year. However, because the adjustment was included so late in the proceeding and because the Public Staff has not had time to audit it, the Company and Public Staff agreed that the $294,198 would be reviewed in next year's fuel proceeding.

Q. HOW DO THESE TWO ADJUSTMENTS IMPACT THE EMF DECREMENT BILLING FACTORS BEING PROPOSED BY DEC IN THIS FUEL PROCEEDING?

A. The net of the two adjustments increased the overall overrecovery of North Carolina retail fuel and fuel-related costs to $51,555,143, producing an overall EMF decrement billing factor of (0.0928) ¢/kWh. This factor was calculated by dividing the fuel and fuel-related cost overrecovery by DEC's test year North Carolina retail sales, adjusted for customer growth and weather, of 55,534,610 MWH. The adjustment increased the overrecovery for the residential customer class to $9,676,332, the commercial customer class to $25,992,843, and the industrial customer class to $15,885,968. The adjusted EMF decrement billing factors were calculated by dividing the adjusted fuel and fuel-related cost overrecoveries by Duke's test year North Carolina retail sales, adjusted for customer growth and weather, of 21,143,695 MWH for the residential customer class, 22,112,646 MWH for the commercial customer class, and 12,278,269 MWH for the industrial class, resulting in the following adjusted EMF decrement billing factors.

Customer Class	Adjusted EMF Decrement Factors
Residential	(0.0458) ¢/kWh
Commercial	(0.1175) ¢/kWh
Industrial	(0.1294) ¢/kWh

The calculations for the adjusted EMF decrement billing factors are shown on Stipulation Exhibit 2, Schedules 1 through 4, attached to the Stipulation.

Q. DID THESE ADJUSTMENTS INCREASE THE EMF INTEREST DECREMENT BILLING FACTORS?

A. Yes. The net of the two adjustments increased the overall interest amount to $8,592,520, producing an overall EMF interest decrement of (0.0155) ¢/kWh. The adjusted interest for the residential customer class is $1,612,721, for the commercial customer class it is $4,332,139, and for the industrial customer class it is $2,647,660. The adjusted EMF interest decrement billing factors were calculated by dividing the adjusted interest amounts by Duke's test year North Carolina retail sales, adjusted for customer growth and weather, of 21,143,695 MWH for the residential customer class, 22,112,646 MWH for the commercial customer class, and 12,278,269 MWH for the industrial class, resulting in the following adjusted EMF interest decrement billing factors.

Customer Class	Adjusted EMF Interest Decrement Factors
Residential	(0.0076) ¢/kWh
Commercial	(0.0196) ¢/kWh
Industrial	(0.0216) ¢/kWh

The calculations for the adjusted EMF interest decrement billing factors are shown on Stipulation Exhibit 2, Schedules 1 through 4, attached to the Stipulation.

Q. WHAT EMF DECREMENT BILLING FACTORS DOES THE PUBLIC STAFF RECOMMEND?

A. The Public Staff recommends approval of the following adjusted EMF decrement billing factors as presented in the Stipulation.

Customer Class	Adjusted EMF Decrement Factors
Residential	(0.0458) ¢/kWh
Commercial	(0.1175) ¢/kWh
Industrial	(0.1294) ¢/kWh

The Public Staff also recommends approval of the following adjusted EMF interest decrement billing factors as presented in the Stipulation.

Customer Class	Adjusted EMF Interest Decrement Factors
Residential	(0.0076) ¢/kWh
Commercial	(0.0196) ¢/kWh
Industrial	(0.0216) ¢/kWh

I have provided this information to Public Staff witness Kennie Ellis for incorporation into his recommended final fuel factor and testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Randy T. Edwards

I am a graduate of Barton College (formerly Atlantic Christian College), at Wilson, N. C., with a Bachelor of Science degree in Accounting. Prior to joining the Public Staff, I was employed by Carolina Power & Light Company. My duties involved supervising accounting activities, preparing financial reports, and marketing energy services. I joined the Public Staff as a Staff Accountant in October 1998.

I am responsible for analyzing testimony, exhibits and other data presented by parties before this Commission. I have the further responsibility of performing examinations of books and records of utilities involved in proceedings before the Commission, and summarizing the results into testimony and exhibits for presentation to the Commission.

Since joining the Public Staff, I have filed testimony or affidavits in fuel rate cases of Duke Power, PEC, and DNCP, as well as in water and sewer general rate cases.

I have also been involved in several other matters that have come before this Commission, including the review and investigation of the electric utilities' funding practices for nuclear decommissioning cost (Docket No. E-100, Sub 56), the Nantahala Power & Light Purchased Power Cost Rider (Docket No. E-7, Sub 717), and several other applications related to electric utilities.

BY MS. DOWNEY:

Q Mr. Edwards, do you have a summary of your testimony?

A (Mr. Edwards) I do.

Q Would you please read that for the Commission.

A (Summary read into the record.)

SUMMARY OF TESTIMONY OF RANDY T. EDWARDS
DOCKET NO. E-7, SUB 1033

With its application filed on March 7, 2013, DEC filed the direct testimony and exhibits of its witness Kim H. Smith proposing a North Carolina retail fuel and fuel-related cost overrecovery of $47,306,484 for the test year ending December 31, 2012. DEC did not include actual fuel and fuel-related costs and revenues incurred for January through April 2013 as permitted by G.S. 62-133.2(d).

My investigation included the examination and analysis of testimony, exhibits, books and records, and other data presented by DEC and other parties under the jurisdiction of the Commission. If reflected in rates beginning September 1, 2013, the class-specific components of the $47,306,484 divided by the class-specific components of the Company's test year retail sales, adjusted for customer growth and weather, of 55,534,610,000 kWh, would result in the following EMF decrement billing factor for each customer class:

Customer Class	EMF Decrement Factors
Residential	(0.0382) ¢/kWh
Commercial	(0.1099) ¢/kWh
Industrial	(0.1216) ¢/kWh

Applicable interest on the $47,306,484 was $7,884,411 which resulted in the following EMF interest decrement billing factor for each customer class:

Customer Class	EMF Interest Decrement Factors
Residential	(0.0064) ¢/kWh
Commercial	(0.0183) ¢/kWh
Industrial	(0.0203) ¢/kWh

On June 3, 2013, the Public Staff and DEC filed a Joint Agreement and Stipulation of Settlement (Stipulation). Through the Stipulation, DEC is updating its filing to reflect the impact of $294,198 (NC retail) fuel costs incurred in 2012 that were inadvertently omitted in its original filing, and DEC will forgo recovery of $4,542,857 of replacement power fuel expenses incurred during the test year due to the outage extension at McGuire, as well as $757,143 of interest on that amount. The inclusion of these amounts in the EMF decrement and EMF interest decrement factor calculation results in the following adjusted EMF decrement billing factor for each customer class

Customer Class	Adjusted EMF Decrement Factors
Residential	(0.0458) ¢/kWh
Commercial	(0.1175) ¢/kWh
Industrial	(0.1294) ¢/kWh

Customer Class	Adjusted EMF Interest Decrement Factors
Residential	(0.0076) ¢/kWh
Commercial	(0.0196) ¢/kWh
Industrial	(0.0216) ¢/kWh

This concludes my summary.

BY MS. DOWNEY:

Q Mr. Hoard, would you please state your name, business address and present position.

A My name is James G. Hoard. I am Director of the Public Staff's Accounting Division, and my business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q Did you prepare and cause to be filed on June 3, 2013 testimony in this case consisting of 10 pages?

A Yes.

Q And an appendix?

A Yes.

Q Do you have any corrections or changes to that testimony at this time?

A No.

Q If the same questions were asked of you today, would your answers be the same?

A Yes.

MS. DOWNEY: Mr. Chairman, I would move that the direct testimony of the witness be copied into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Hoard's direct prefiled testimony filed on June 3, 2013, consisting of 10 pages and his appendix shall be copied into the record as if given orally from the stand.

(Whereupon, the prefiled testimony of James G. Hoard and Appendix A was copied into the record as if given orally from the stand.)

DUKE ENERGY CAROLINAS, LLC
DOCKET NO. E-7, SUB 1033

TESTIMONY OF JAMES G. HOARD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

June 3, 2013

Q. PLEASE STATE FOR THE RECORD YOUR NAME, ADDRESS, AND PRESENT POSITION.

My name is James G. Hoard. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Public Staff – Accounting Division.

Q. WHAT ARE YOUR DUTIES?

A. I am responsible for the organization, planning, and performance of the work of the Public Staff Accounting Division, which includes, among other things, the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings.

Q. PLEASE DISCUSS YOUR EDUCATION AND EXPERIENCE.

A. A summary of my education and experience is attached as Appendix A.

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

A. The purpose of my testimony is provide comments on the merger-related fuel savings reported by Duke Energy Carolinas, LLC (DE Carolinas) in its monthly fuel reports (MFRs) filed with the Commission and explain how those fuel savings have been reflected in the Company's actual total fuel and fuel-related costs in this proceeding during the test period ended December 31, 2012.

Q. PLEASE EXPLAIN THE REQUIREMENTS THAT PERTAIN TO THE TRACKING OF MERGER-RELATED FUEL SAVINGS.

A. Pursuant to the Commission's June 29, 2012 Order, in Docket No. E-2, Sub 998 and E-7, Sub 986 (Merger Order), the North Carolina retail customers of DE Carolinas and DE Progress (Utilities) have been guaranteed receipt of their allocable share of $650 million[1] in fuel and fuel-related cost savings resulting from the merger over a five-year period through the annual fuel charge proceedings of the Utilities. The five-year period may be extended by 18 months if ratepayers have not received their allocable share of the guaranteed savings at the end of the five-year period and the decline in natural gas prices has resulted in the delivery of less coal to certain DE Carolinas coal-fired plants. In addition, DE Carolinas and DE Progress are required to file monthly reports of tracked fuel savings with their MFRs filed under Commission Rule R8-52. These

[1] A settlement agreement approved by the Commission on December 3, 2012, in Docket No.E-7, Sub 1017, requires an additional $25 million in fuel and fuel-related savings for North Carolina retail ratepayers. The Company has grossed-up the $25 million additional guarantee amount to $36.8 million to include amounts due to South Carolina retail ratepayers and wholesale customers in both states. The total amount of guaranteed savings is now $686.8 million.

reports of tracked fuel savings must show fuel savings broken down by the following categories: (a) total system, (b) DE Carolinas, (c) DE Carolinas North Carolina retail, (d) DE Progress, and (e) DE Progress North Carolina retail. If at the end of the guaranteed savings period the North Carolina retail customers of the Utilities have not received their allocable shares of the guaranteed fuel savings, the remaining amount shall be reflected as an adjustment in the first fuel cost proceedings of DE Carolinas and DE Progress following the end of the guaranteed savings period.

Q. HAVE DE CAROLINAS AND DE PROGRESS FILED THE TRACKED FUEL SAVINGS REPORTS AS REQUIRED BY THE MERGER ORDER?

A. Yes. The Utilities filed these reports as Schedule 11 of their respective MFRs. Through December 31, 2012, the Utilities have reported cumulative combined fuel savings of $51,869,687.

Q. PLEASE DESCRIBE THE FUEL SAVINGS THAT THE UTILITIES HAVE ACHIEVED THROUGH THE END OF THE TEST PERIOD AND HOW THEY ARE ACCOUNTED FOR AND REFLECTED IN THE MONTHLY FUEL REPORTS.

Presented below is a chart that shows details of the fuel savings reported by the Utilities.

TABLE 1

Item	DE Carolinas	DE Progress	Combined
	(a)	(b)	(c)
Joint Dispatch	$11,328,001	$2,820,299	$14,148,300
Coal Blending	23,524,131		23,524,131
Coal Procurement	1,624,630	2,475,010	4,099,640
Coal Transportation	2,181,451	1,805,939	3,987,390
Reagent Procurement & Transportation	450,300	689,849	1,140,149
Natural Gas Supply & Capacity	4,754,353		4,754,353
Avoided Trading Desk	215,724		215,724
Total	$44,078,590	$7,791,097	$51,869,687

The combined amounts shown in column (c) above are the sum of the savings that originated in each utility. These fuel savings are reflected in the actual expenses reported by the originating utility; the amount of the combined fuel savings is allocated between DE Carolinas and DE Progress each month based on the Utilities' relative mWh generation. As a result, an accounting entry has been recorded each month since the merger closed to transfer savings that exceed the allocated share of the originating utility to the other utility. TABLE 2 below shows the amount of fuel savings that were transferred by DE Carolinas to DE Progress during the test period.

TABLE 2

Item	DE Carolinas Gross Amount (a)	DE Carolinas Allocated Share (b)	DE Carolinas Transferred (c)
Joint Dispatch	$11,328,001	$8,316,083	$3,011,918
Coal Blending	23,524,131	17,514,516	6,009,615
Coal Procurement	1,624,630	2,399,044	(774,414)
Coal Transportation	2,181,451	2,165,421	16,030
Reagent Procurement & Transportation	450,300	560,574	(110,274)
Natural Gas Supply & Capacity	4,754,353	2,807,572	1,946,781
Avoided Trading Desk	215,724	127,539	88,185
Total	$44,078,590	$33,890,749	$10,187,841

The total amount shown in column (c) is the difference between the gross amount originating with DE Carolinas and its allocated share of combined savings. The Joint Dispatch amount shown above is composed of the savings transferred to DE Progress of $3,558,502 that is included in Schedule 3 of the MFRs as Purchased Power, less the savings transferred from DE Progress of $546,584 that is included as Intersystem Sales. The increase in DE Carolinas' Purchased Power (debit) represents the DE Progress portion of Joint Dispatch savings that DE Carolinas realized on Joint Dispatch transactions, including energy transfers provided by DE Progress. The increase in DE Carolinas' Intersystem Sales (credit) represents the DE Carolinas' portion of Joint Dispatch savings that DE Progress realized on Joint Dispatch transactions, including energy transfers provided by DE Carolinas.

The Coal Blending, Coal Procurement, and Coal Transportation fuel savings amounts transferred between DE Carolinas and DE Progress are reflected in the Steam Generation section, Account 0501016, of MFR Schedule 2, page 1 of 2. All of the Coal Blending savings originate in DE Carolinas, because they result from the implementation of coal blending at the DE Carolinas coal-fired plants. DE Progress, which implemented coal blending at its coal-fired plants in 2006, already has considerable experience with coal blending. Because DE Progress fully implemented coal blending before the merger, there are no merger-related coal blending savings for the DE Progress coal-fired plants. DE Carolinas, however, began some coal blending activities at its Marshall Steam Plant prior to the merger, so the Utilities have excluded a portion of these savings from the computation of merger-related Coal Blending savings. The Coal Procurement and Coal Transportation savings result from renegotiated and new contracts that the Utilities have entered into with coal and coal transportation services providers, and thus savings originate in both Utilities.

Similarly, the Reagent Procurement and Transportation savings amounts result from renegotiated and new contracts that the Utilities have entered into with reagent and reagent transportation services providers. The net Reagent Procurement and Transportation savings amount transferred to DE Carolinas of $110,274 is reflected as a credit to Account 502160 – Reagent Procurement Merger Savings on Schedule 2, page 1 of 2, of the MFR. All of the savings related to coal and reagent procurement and transportation reported through December 31, 2012, result from contract negotiations and renegotiations with fuel supply and transportation vendors that were premised upon the merger, but undertaken by the Utilities prior to its closing.

The Natural Gas Supply and Capacity savings amount is composed of savings on purchases of gas supply, pipeline capacity costs, and purchases of oil. MFR Schedule 2, Account 0547123 reflects $1,946,781 for the transfer of savings from DE Carolinas to DE Progress.

The Avoided Trading Desk savings amount is a non-fuel and fuel-related cost item that is reflected on MFR, Schedule 2, page 2 of 2, in Account 0547127. Due to the merger, only one natural gas trading desk is needed by the Utilities. As a result, the Utilities have avoided the personnel and related costs for a second trading desk that would have been needed had the Utilities not merged. The Avoided Trading Desk savings have been counted towards the fuel savings guarantee, but do not flow through the fuel clause.

Q. HAVE ANY ADDITIONAL FUEL SAVINGS TRANSFERS BEEN REFLECTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes. Company witness Smith has reflected an adjustment to her Experience Modification Factor (EMF) computation for pre-merger savings that DE Carolinas believes should be shared with DE Progress. DE Carolinas has not yet reflected the transfer of these savings from DE Carolinas to DE Progress in fuel and fuel-related expenses. The North

Carolina retail amount of these savings, which total $2,282,619,[2] is reflected on Smith Exhibit 3, pages 1 through 4, and decreases the over-collection that Company witness Smith has reflected in the EMF computation for the test period. The computation of this amount is shown on Smith Workpaper 18. Company witness Smith states in her testimony, at page 12, lines 18-22, that "[U]pon approval by the Commission to adjust the over-collection for calendar year 2012 to reflect the sharing of merger fuel related savings achieved during the period prior to the merger close, the Company will make the appropriate entries on its books to reflect the sharing of the savings."

Both Utilities benefit from the merger-related fuel savings, and the Company's proposal to share pre-merger fuel savings between the two Utilities is consistent with the treatment of post-merger fuel savings. Consequently, the Public Staff does not oppose this entry as long as DE Progress reflects the full offsetting amount in its upcoming fuel proceeding. The test period for DE Progress in its upcoming fuel proceeding begins April 1, 2012, so some of the pre-merger period pre-dates the DE Progress test period. To ensure that ratepayers receive the full benefit of the savings, the offsetting entry made in the DE Progress proceeding should include savings for the January through March 2012, period that occurs prior to the beginning of the fuel proceeding test period.

[2] The total system DE Carolinas amount of transferred savings is $3,348,031.

Q. DO YOU HAVE ANY COMMENTS ON THE AMOUNTS OF FUEL SAVINGS THAT HAVE BEEN REPORTED BY THE COMPANIES?

A. The Public Staff has reviewed the tracked fuel savings computations but has not yet confirmed the validity of the amounts. The Public Staff will continue to review these fuel savings with due diligence. Should the Commission approve adjustments to the cumulative amount of reported fuel savings in a future proceeding, the Public Staff recommends that the accounting and ratemaking treatment of the adjustments be addressed at that time.

Q. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S ACCOUNTING PRACTICES REGARDING THE FUEL SAVINGS?

A. Yes. I am concerned about the numerous true-ups that appeared in the fuel savings calculations during the test period. These true-ups resulted from a variety of computational refinements and were not limited to the month immediately following the accounting month when the activity occurs. For example, an accounting month may have contained fuel savings adjustments for several prior periods, each of which had to be allocated between the Utilities based on that prior period's mWh resource generation allocation factors. As a result, the fuel savings recorded during an accounting month had several layers, an allocation between the Utilities for the current accounting month and allocations for each prior period. The Company has investigated the cause of the prior period true-up adjustments and implemented changes in April 2013 that it believes should reduce the number and amount of the adjustments. My understanding, however, is that the Utilities will continue to have minimal Joint Dispatch true-ups each month due to a pumped storage timing issue.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

JAMES G. HOARD

Qualifications and Experience

I graduated from the University of Rhode Island in 1979 with a Bachelor of Science degree in Business Administration. Subsequent to graduation I have completed various economics, statistics, and regulatory courses. I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants.

I joined the Public Staff as a Staff Accountant in October, 1979, and was promoted to Supervisor of the Electric Section in January 1984. At the end of 1985, I assumed the position of manager in a small regional certified public accounting firm. In September 1987 I rejoined the Public Staff. On August 1, 2000, I was promoted to Assistant Director of the Accounting Division, and on October 2, 2012, I was promoted to Director of the Accounting Division. In my present position, I am responsible for the organization, planning, and performance of the work of the Public Staff Accounting Division, which includes, among other things, the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings. I have testified before the Commission on many occasions addressing a wide range of topics and issues.

BY MS. DOWNEY:

Q Mr. Hoard, do you have a summary of your testimony?

A Yes.

Q Would you please that for the Commission.

A (Summary read into the record.)

DUKE ENERGY CAROLINAS, LLC
DOCKET NO. E-7, SUB 1033

SUMMARY OF THE TESTIMONY OF JAMES G. HOARD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

June 3, 2013

The purpose of my testimony is provide comments on the merger-related fuel savings reported by Duke Energy Carolinas, LLC (DE Carolinas) in its monthly fuel reports (MFRs) filed with the Commission and explain how those fuel savings have been reflected in the Company's actual total fuel and fuel-related costs in this proceeding during the test period ended December 31, 2012. The Public Staff has reviewed the tracked fuel savings computations but has not yet confirmed the validity of the amounts. The Public Staff will continue to review these fuel savings with due diligence. Should the Commission approve adjustments to the cumulative amount of reported fuel savings in a future proceeding, the Public Staff recommends that the accounting and ratemaking treatment of the adjustments be addressed at that time.

This concludes the summary of my testimony.

BY MS. DOWNEY:

Q Mr. Ellis, would you please state your name, business address and present position?

A Yes. My name is Kennie D. Ellis. My business address is 430 North Salisbury Street in Raleigh, North Carolina, and I'm an engineer in the Public Staff Electric Division.

Q Did you prepare and cause to be filed on June 3, 2013 testimony in this case consisting of 18 pages and an appendix?

A I did.

Q Do you have any corrections or changes to that testimony at this time?

A I do not.

Q If the same questions were asked of you today, would your answers be the same?

A They would.

MS. DOWNEY: Mr. Chairman, I would move that the direct testimony of Mr. Ellis be copied into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Ellis' direct prefiled testimony consisting of 18 pages, filed on June 3, 2013, shall be copied into the record as though given orally from the stand, as well as his appendix shall be copied into the record as though given orally from the stand.

(Whereupon, the prefiled direct direct testimony and Appendix A of Kennie D. Ellis was copied into the record as though given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1033

TESTIMONY OF KENNIE D. ELLIS ON BEHALF OF THE PUBLIC STAFF

June 3, 2013

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

A. My name is Kennie D. Ellis. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff, North Carolina Utilities Commission.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

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

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

A. The purpose of my testimony is to present the results of the Public Staff's investigation of the application filed by Duke Energy Carolinas, LLC (DEC or the Company) in this docket on March 6, 2013, in the areas of power plant performance and fuel and fuel-related costs. My testimony is also intended to support the Joint Agreement and Stipulation of Settlement entered into by DEC and the Public Staff with respect to nuclear plant performance.

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

A. The investigation included a review of the Company's test period and projected fuel and fuel-related costs and also the following: (1) the Company's application and testimony and voluminous responses to Public Staff data requests; (2) the performance of the Company's base load power plants, including the Company's fleet of nuclear facilities during the test year; (3) Company reports and Nuclear Regulatory Commission (NRC) documents; (4) the Company's purchased power transactions; (5) the cost of renewables and associated fuel prices; (6) the Company's coal, natural gas, nuclear, and reagent procurement practices and contracts; and (7) the current state of coal, natural gas, nuclear fuel, and reagent markets. I also had multiple discussions with Company personnel concerning the performance of its nuclear facilities.

Q. WHAT WAS THE FOCUS OF THE INVESTIGATION RELATING TO THE PERFORMANCE OF DEC'S NUCLEAR FACILITIES?

A. G.S. 62-133.2(d) provides, among other things, that the burden of proof as to the correctness and reasonableness of the charge and as to whether the cost of fuel and fuel-related costs were reasonably and prudently incurred is on the utility, and that the Commission shall allow only that portion of fuel costs prudently incurred under efficient management and economic operations.

Commission Rule R8-55(k), which was adopted pursuant to G.S. 62-133.2(d1), provides that for purposes of determining the experience modification factor (EMF), a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Corporation's (NERC) Generating Availability Report, appropriately weighted for size and type of plant or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant. If a utility does not achieve either standard, a rebuttable presumption is created that the utility incurred the increased cost of fuel and fuel-related costs imprudently, and a disallowance of the increased costs is appropriate.

As stated by Company witness Duncan on page 7 of his direct testimony, the most recent NERC five-year average, weighted for size and type of reactor in DEC's nuclear generation system, was 89.79%. Since the Company's nuclear generation system achieved an overall actual capacity factor of 91.85% during the test period, no presumption of imprudence or disallowance of increased fuel costs was created under Rule R8-55(k). However, the rule states that the burden of proof as to the correctness and reasonableness of any charge shall be on the utility.

In particular, the Company's proposed EMF reflects increased fuel costs resulting from the purchase of replacement power during the Catawba Unit 1 forced outage in April of 2012, the extension of the Catawba Unit 2 refueling outage during that same time period, and the extension of the McGuire Unit 2 refueling outage in the fall of 2012. Therefore, the Public Staff undertook to determine what caused these outages and outage extensions, whether the additional costs were reasonable and prudently incurred, and; if not, what adjustment to the Company's proposed EMF is appropriate.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR INVESTIGATION INTO THE CATAWBA AND MCGUIRE OUTAGES.

A. The Public Staff's investigation of the Catawba and McGuire outages revealed the following information.

Catawba Units 1 and 2

In the spring of 2012, Catawba Unit 1 was operating at full power, while Catawba Unit 2 was in a scheduled refueling outage that had begun on March 10, 2012. On April 4, 2012, Catawba Unit 1 tripped following a trip of a reactor coolant pump. When generator power circuit breakers opened, the Zone G protective relaying system unexpectedly actuated, opening the switchyard breakers, isolating Unit 1 and resulting in a Loss of Offsite Power (LOOP). Because Unit 2's essential busses were aligned to Unit 1's offsite power at the time, those busses lost power when the LOOP occurred. The Company investigated the causes behind both the trip of the reactor coolant pump and the actuation of the Zone G protective relaying system.

The Company found that the trip of the reactor coolant pump occurred as a result of a phase to ground fault in the Y phase conductor (a power cable) for the pump motor.. In 2000, this reactor coolant pump experienced a similar trip as a result of the pump motor Y phase Elastimold bushing fault to ground, which likely caused thermal damage to the cable and ultimately led to the cable failure that occurred in the spring of 2012.

With respect to the unexpected actuation of the Zone G relaying system that resulted in the LOOP, the Company determined that during Catawba Unit 1's scheduled outage in 2011, the generator protective relaying was upgraded. The modification (Zone G relay modification) was intended to maximize the reliability of the protective relaying function while minimizing the likelihood of spurious relay actuation. The modification consisted, in part, of adding a redundant train of protective relays for each function and adding two additional functions. The Zone G relaying system trips the switchyard unit tie breakers in the event of a generator underfrequency, separating the turbine generator from the grid. The modification was supposed to include a blocking logic. This blocking logic was not fully incorporated into the Zone G digital relay upgrades.

The omission of the blocking logic from the relay programming was not discovered during the testing phase of the modification because the testing procedures were based upon a calculation that was generated during the vendor's design portion of the modification rather than upon the original design specifications. Consequently, the programming error propagated through the rest of the implementation phase and was undetected during design, review, approval, implementation, and post-modifiication testing.

As a result of the omission of the blocking logic, when the reactor trip occurred due to the coolant pump trip, the relay mistakenly detected a generator underfrequency and unexpectedly opened, separating the generator from the grid and causing a LOOP.

Catawba Unit 1 was in a forced outage until April 17, 2012, a total of 13 days as result of the above-described events.

The faulty Zone G relay design error was also present in the relay system for Catawba Unit 2. If Unit 2 had been restarted and operated at power, a turbine trip may have resulted in a LOOP on Unit 2. Consequently, Catawba Unit 2's planned outage was extended an additional 10 days, until April 17, 2012, in part to correct the relay sequence design error.

McGuire Unit 2 Outage Extension

The McGuire Unit 2 outage involved not only the refueling of the unit, but also the replacement of the generator stator and high pressure turbine rotor. While the Company had experience with replacing this type of equipment, this was a significant project for McGuire and was one of the largest projects of its kind in Duke's nuclear history. The contract to perform this work was awarded to Siemens USA (Siemens), which manufactured the stator. The outage started on September 15, 2012.

Soon after the outage began, vendor-related human performance issues emerged. Duke and Siemens management repeatedly reminded workers to return to appropriate behaviors to minimize hazards. In a letter to Siemens dated October 4, 2012, Company management expressed dissatisfaction with Siemens' implementation performance, which included not only injuries and dropped objects, but also issues with foreign material in the generator stator and foreign material exclusion (FME) control issues.

FME controls are developed and utilized to ensure that all tools and personnel entering in a FME area are logged in and checked for loose items, and checked again when exiting the FME area. Tools are checked for loose or missing parts, and workers are checked for loose items, such as coins or pens.

On October 14, 2012, during the course of the replacement of the main generator stator, it was discovered that a 5/16" nut and washer were missing from a tool (known as a "come along") that was used during the stator rebuild. The tool had been inspected and logged before being brought into the FME area. At the time it was discovered that the nut and washer were missing, the generator rotor had already been reinstalled, and the turbine end and exciter end of the generator were being built. Due to the risks associated with leaving the parts in the generator, Company management decided to undertake a search for the nut and washer by removing the generator rotor to ensure all foreign materials were in fact removed. The nut and washer were never found, but the Company did find metallic drill tailings from initial fabrication and installation, one of which was four inches long, which could have caused significant damage had they not been removed.[1] The search for the nut and washer, removal of the foreign material found, and reinstallation of the turbine rotor extended the outage for an additional 10 days.

On October 17, 2012, the Company again sent Siemens a letter expressing dissatisfaction with Siemens' performance. The Company requested a face to face meeting to discuss a recovery plan for the project.

On October 26, 2012, Siemens began to undertake final generator alignment. In undertaking this activity, it is important that the weight of the generator is evenly distributed on its four corners; otherwise, an unacceptable and unsustainable amount of vibration can result. Siemens recommended performing Frame Foot Loading (FFL)

[1] A loose metallic part left in the main generator (especially the windings or stator core) can result in damage to the windings, fault of the stator, subsequent generator, turbine and reactor trip, the potential for a complicated trip (e.g. a LOOP) due to protective relay actuations, the potential for release of hydrogen from the generator, the risk of explosive gas and fire, catastrophic failure, and personal injury.

using strain gauges to ensure that the weight of the generator was evenly distributed on the four corners of the generator. Although the FFL method is commonly used in the industry, the Company's experience with aligning generators had been to use the step shimming method, which steps down the shim configuration from the four corners of the generator to ensure the load is distributed appropriately. The Company agreed, however, with the use of FFL to accomplish this task.

Alignment using FFL progressed well at first, but early on October 29, 2012, Siemens personnel began to note inconsistent and unexpected readings from the gauges. The Company's review of the FFL data indicated that the data was unpredictable and unreliable. In reviewing the details of the data on various moves made, Duke questioned the adequacy of Siemens' process controls and verification of key data points. Ultimately, the Company stopped the FFL process and resorted to using the manual validation of step shimming, but the poor execution of the FFL resulted in a delay of almost 5 days.

The McGuire Unit 2 outage ended on November 30, 2012, approximately 38 days longer than originally scheduled.

Q. WHAT CONCERNS DID THE PUBLIC STAFF IDENTIFY CONCERNING THESE OUTAGES?

A. The causes and events leading up to the Catawba Unit 1 forced outage and the extensions of the Catawba Unit 2 and McGuire Unit 2 refueling outages led to concerns that the increased costs of fuel necessary for replacement power during some of the outage days in question were attributable, at least in part, to events that could have been prevented by DEC under efficient management. Since the fuel costs incurred to serve DEC's customers and the corresponding EMF proposed in this case would have been lower but for these delays, the Public Staff believes that a portion of these costs should not be charged to ratepayers.

Although the Public Staff understands that the Company had in place oversight processes beyond those typically required for non-safety-related modifications and should have detected the programming error, it believes that omission of the blocking logic from the Zone G protective relaying system, resulting in a LOOP at Catawba 1 and an extension of the Catawba 2 outage could have been avoided under the exercise of efficient management. With respect to the McGuire Unit 2 outage, the Public Staff believes that DEC is ultimately responsible for the performance of all personnel involved in performing work related to the outage, including contracted vendors tasked with specific projects. Although the Company provided project management oversight to Siemens that identified issues and directed the implementation of corrective actions, the Public Staff also believes that DEC's ratepayers should not be charged rates that include the increased cost of fuel necessary for replacement power due to the outage extension resulting from Siemens' poor performance.

However, notwithstanding the circumstances surrounding the Catawba and McGuire outages, and the delays and increased fuel costs involved, the Public Staff recognizes that reasonable persons with knowledge and experience in nuclear operations can disagree as to the prudence of specific actions or inactions that caused delays and resulted in increased fuel costs during an outage, particularly an outage that included major upgrades to a unit in a nuclear fleet that met the NERC five-year average. Moreover, the Public Staff acknowledges that the Company made efforts to mitigate the effects of the delays at McGuire caused by Siemens' performance and developed recovery plans for the project in conjunction with Siemens, and believes that DEC's decision to remove the rotor to conduct further searches for a potential missing nut and washer were reasonable and prudent under the circumstances. Likewise, the Company developed corrective action plans for the Catawba LOOP event aimed at preventing future such events. Considering all of these factors, the Public Staff believed it appropriate to engage in settlement discussions with DEC regarding an adjustment to test period fuel costs that would be fair to the Company and to its ratepayers. These discussions resulted in a stipulated adjustment of $5.3 million on a North Carolina retail basis, including interest, of which $4,542,857 represents the cost of replacement power. In addition, the Company agrees to return to ratepayers in a future fuel case, one-half of the net amount it ultimately recovers from Siemens, up to $257,143. The Public Staff believes these provisions represent a fair and reasonable resolution of the issue of the performance of the Company's nuclear plants in this proceeding.

Q. WHAT ABOUT THE OTHER NUCLEAR OUTAGES THAT OCCURRED DURING THE TEST YEAR?

A. Oconee Unit 1 completed a spring 2012 refueling outage which required a five-day extension based on vent valve replacement. Oconee Unit 2 completed a refueling outage in the fall of 2012. However, the Public Staff considers these outages and associated extensions to be within the scope of expected plant operations, and, therefore, not to warrant any replacement power cost disallowance. Overall, except for Catawba Units 1 and 2 and McGuire Unit 2, the DEC nuclear fleet performed well during the test year as discussed by Duke witness Duncan in his prefiled testimony.

Q. WHAT ARE THE PUBLIC STAFF'S CONCLUSIONS REGARDING THE COMPANY'S PROJECTED FUEL COSTS?

A. Based upon its investigation, the Public Staff has determined that the projected fuel prices set forth in the application were calculated appropriately for this proceeding. The projected cost for fuel and fuel-related costs were affected by a small projected increase in the price of natural gas as evidenced by the Henry Hub projected forward prices. In addition, nuclear fuel costs also increased from the test year. The increases in natural gas and nuclear costs are offset by a slightly lower delivered price of coal, as well as merger related fuel savings and joint dispatch savings. DEC's projected fuel and fuel-related costs are based on a 92.84% nuclear capacity factor, which is what DEC anticipates for the twelve months from September 1, 2013, through August 31, 2014, the period the new rates will be in effect.

Q. **DID THE PUBLIC STAFF REVIEW THE CALCULATIONS OF THE VARIOUS FUEL FACTOR COMPONENTS?**

A. Yes. The prospective components of the total fuel factor have been calculated in accordance with the requirements of G.S. 62-133.2. The Public Staff has reviewed the calculations of the various fuel factor components and agrees with them.

Q. **DID THE PUBLIC STAFF REVIEW THE EMF CALCULATIONS?**

A. Yes. Public Staff witness Edwards has reviewed the revised calculation of DEC's revenue overcollection of $51,555,143 set forth in the Stipulation and agrees with it.

Q. **WHAT IS THE PUBLIC STAFF'S RECOMMENDATION?**

A. The Public Staff recommends approval of the following components and total fuel factors (excluding GRT) documented in Table 1 effective for the twelve months beginning September 1, 2013:

TABLE 1 – Total Proposed Fuel and Fuel-Related Cost Factors Excluding GRT

Rate Class	Base & Prospective Component	EMF Component	Total Fuel Factor
Residential	2.2306 ¢/kWh	(0.0534) ¢/kWh	2.1772 ¢/kWh
General Service/Lighting	2.3566 ¢/kWh	(0.1371) ¢/kWh	2.2195 ¢/kWh
Industrial	2.3980 ¢/kWh	(0.1510) ¢/kWh	2.2470 ¢/kWh

(Excluding Currently Approved Base Fuel Factor and GRT)
(Note Base Fuel Factor = 2.3935¢/kWh as approved in Docket E-7, Sub 989)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	(0.1629) ¢/kWh	(0.0534) ¢/kWh	(0.2163) ¢/kWh
General Service/Lighting	(0.0369) ¢/kWh	(0.1371) ¢/kWh	(0.1740) ¢/kWh
Industrial	0.0045 ¢/kWh	(0.1510) ¢/kWh	(0.1465) ¢/kWh

In addition, for comparison with the previously approved rates, the Public Staff submits the following table (Table 2) to summarize the impact of the proposed changes including GRT.

TABLE 2 – Fuel and Fuel Related Cost Factors (Including GRT)
(Note Base Fuel Factor = 2.3935¢/kWh as approved in Docket E-7, Sub 989, and with the application of GRT, this base fuel factor would result in a revenue amount of 2.4762 ¢/kWh.)

With GRT approved in the last Docket E-7, 1002

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	(0.1770) ¢/kWh	0.0372 ¢/kWh	(0.1398) ¢/kWh
General Service/Lighting	(0.1523) ¢/kWh	0.0334 ¢/kWh	(0.1189) ¢/kWh
Industrial	(0.1387) ¢/kWh	0.0329 ¢/kWh	(0.1058) ¢/kWh

Proposed in this Docket E-7, Sub 1033 (including GRT)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	(0.1685) ¢/kWh	(0.0552) ¢/kWh	(0.2237) ¢/kWh
General Service/Lighting	(0.0382) ¢/kWh	(0.1418) ¢/kWh	(0.1800) ¢/kWh
Industrial	0.0047 ¢/kWh	(0.1562) ¢/kWh	(0.1515) ¢/kWh

Summary of Differences Sub 1033 – Sub 1002 (including GRT)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	0.0085 ¢/kWh	(0.0924) ¢/kWh	(0.0839) ¢/kWh
General Service/Lighting	0.1141 ¢/kWh	(0.1752) ¢/kWh	(0.0611) ¢/kWh
Industrial	0.1434 ¢/kWh	(0.1891) ¢/kWh	(0.0457) ¢/kWh

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

KENNIE D. ELLIS

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Engineering with a concentration in nuclear power.

I began my employment with the Public Staff Electric Division in May of 2003. While with the Electric Division, my primary responsibilities have been fuel factor computation and inventory, generation adequacy, small power and utility generator Certificates of Public Convenience and Necessity, investigation of inquiries and complaints, and management of various tracking databases. I have also worked in the areas of rate analysis and design, revenue analysis and design, nuclear decommissioning, power plant performance, utility service rules and regulations, cost of service, analysis and review of conservation and load management programs, least-cost integrated resource planning, avoided cost, electromagnetic fields, electrical safety, customer growth analysis and validation, unbundling of service, review of wheeling and rates and depreciation analysis.

From October of 1984 until April of 2002, I was employed by Carolina Power & Light Company (Progress Energy Carolinas) primarily at the Shearon Harris Nuclear Power Plant in various capacities including Regulatory Specialist, Operating Experience Coordinator, Corrective Action Program Specialist, Pressure Test Engineer, and Health Physics Technician.

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From 1978 until 1984, I was employed by the United States Navy in the Naval Nuclear Power Program. I was an instructor at the Navy's Nuclear Power Program S5G prototype providing instruction in the areas of Chemistry, Radiochemistry, Radiation Protection and Monitoring, Mechanical Systems, Mechanical Watchstanding, and Integrated Plant Operations. I also served aboard the SSBN-644 (USS Lewis & Clark) as Leading Engineering Laboratory Technician. I was qualified Engine Room Supervisor and all subordinate watchstations.

I have previously filed testimony before the Commission in new certificate applications for generating facilities, fuel proceedings, general rate cases, renewable energy portfolio standards recovery proceedings, and participated in several special investigations.

BY MS. DOWNEY:

Q Mr. Ellis, do you have a summary of your testimony?

A I do.

Q Would you please read that for the Commission?

A Yes. (Summary read into the record.)

SUMMARY OF TESTIMONY OF KENNIE D. ELLIS
DOCKET NO. E-7, SUB 1033

My testimony provides a summary of the investigation of the fuel and fuel-related costs filed by Duke Energy Carolinas, LLC (DEC) in this docket and DEC's power plant performance, and the recommendations of the Public Staff as a result of that investigation. My testimony is also intended to support the Joint Agreement and Stipulation of Settlement (Stipulation) entered into by DEC and the Public Staff in this proceeding.

DEC's EMF reflects increased fuel costs resulting from the purchase of replacement power during outages at Catawba Nuclear Station and McGuire Nuclear Station, Unit 2. The Public Staff undertook to determine what caused these outages, whether the additional costs were reasonable and prudently incurred, and if not, what adjustment to DEC's proposed EMF is appropriate. The Public Staff determined based on its investigation that some of the events at Catawba and McGuire could have been avoided under more efficient management. The Public Staff's findings are more fully discussed in my testimony. Notwithstanding the circumstances surrounding the Catawba and McGuire outages, the Public Staff recognizes that reasonable persons with knowledge and experience in nuclear operations can disagree as to the prudence of specific actions or inactions that caused delays and resulted in increased fuel costs during an outage and that the Company made efforts to mitigate the effects of some of the delays caused by a vendor's performance and developed corrective action plans aimed at preventing future such events. Considering all of these factors, the Public Staff believed it appropriate to engage in settlement discussions with the Company, which ultimately resulted in a stipulated adjustment of $5.3 million in the Experience

Modification Factor (EMF), and an agreement by the Company to return one-half of the net amount it ultimately recovers from its vendor, up to $257,143, in a future fuel case. The Public Staff believes these provisions represent a fair and reasonable resolution of the issue of the performance of the Company's nuclear plants in this proceeding.

My investigation confirmed that the Company's prospective fuel factors were calculated appropriately for this proceeding.

The combination of the recalculated EMF, as reviewed and verified by Public Staff witness Edwards, and the prospective factors verified by me, result in the final Public Staff recommended fuel factors.

This concludes my summary.

MS. DOWNEY: The witnesses are available for cross.

CHAIRMAN FINLEY: Any questions of the witnesses?

(No response.)

CHAIRMAN FINLEY: Questions by the Commission?

(No response.)

CHAIRMAN FINLEY: Very well, gentlemen. Thank you very much.

(Witnesses excused.)

MS. DOWNEY: That concludes our case.

CHAIRMAN FINLEY: Does anyone else have any testimony they wish to provide?

(No response.)

CHAIRMAN FINLEY: Anything else that we need to do as far as evidence in the case this morning?

(No response.)

CHAIRMAN FINLEY: What is your proposal with respect to getting the Commission Proposed Orders?

MR. FRANKLIN: Duke proposed to have a Joint Proposed Order that we'd work on with the Public Staff to the Commission within a month from the date of this hearing.

CHAIRMAN FINLEY: Any objection to that?

MS. DOWNEY: No, sir.

CHAIRMAN FINLEY: Okay. We will look to you for Briefs and Proposed Orders. Anybody else who has intervened in the case is welcome to file whatever they would like to file with us. And with that, if there's nothing further, this part of the proceeding this morning shall be concluded.

(The hearing was adjourned.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-7, Sub 1033, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 9th day of June, 2013.

Linda S. Garrett

Linda S. Garrett

Notary Public No. 19971700150