PLACE: Dobbs Building

Raleigh, North Carolina

DATE: Tuesday, December 5, 2017

TIME: 2:00 p.m. - 4:57 p.m.

DOCKET NO: E-2, Sub 1142

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

Commissioner Bryan E. Beatty

Commissioner ToNola D. Brown-Bland

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

DUKE ENERGY PROGRESS, LLC

Application for Adjustment of Rates and Charges

Applicable to Electric Utility Service

in North Carolina.

VOLUME: 18

Noteworthy
Reporting Services, LLC

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

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

EXAMINATIONS Cont'd

PANEL OF

MICHAEL MANESS and JAY LUCAS

E X H I B I T S

P R O C E E D I N G S:

CHAIRMAN FINLEY: Ms. Downey, your witnesses here?

MS. DOWNEY: Yes, sir. Before we get started, though, yesterday, Mr. Chairman, the Public Staff filed a Second Revised Settlement Exhibit 1 and Second Revised Peedin Schedules, and I believe everyone has copies of those. I would like to move those into evidence.

CHAIRMAN FINLEY: Without objection, those exhibits will be accepted into evidence.

(Whereupon, Second Revised Settlement Exhibit 1 and Second Revised Peedin Exhibit 1 were admitted into evidence.)

MS. DOWNEY: Okay. We also passed out copies of both that and the summaries. If anyone else needs a copy, Shannon over here has extras.

Public Staff calls James McLawhorn and Darlene Peedin.

JAMES McLAWHORN and DARLENE PEEDIN,
having first been duly sworn, were examined
and testified as follows:

DIRECT EXAMINATION BY MS. DOWNEY:

Q. Let's start with you, Mr. McLawhorn. Please state your name, business address, and present position.

A. (James McLawhorn) James McLawhorn, 430 North Salisbury Street, Raleigh, and I'm the director of the Public Staff's electric division.

Q. Mr. McLawhorn, how long have you been with the Public Staff?

A. Too long. No. I have been with the Public Staff for a total of 32 years, 29 of which have been with the electric division.

Q. Did you prepare and cause to be filed, on October 20, 2017, direct testimony in this case consisting of 26 pages and an appendix?

A. Yes, I did.

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

A. I have one correction.

Q. Could you please tell us where that is?

A. Yes. It's on page 9 of my direct testimony, line 17. Page 9, line 17, Mr. -- after Mr. Garrett's name, he's identified as a senior engineer with Garrett and Moore. That should read, he is secretary treasurer of Garrett and Moore.

Q. Is there anything else?

A. No.

Q. Okay. With that correction, if the same questions were asked of you today, would your answers be the same?

A. Yes, they would.

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

CHAIRMAN FINLEY: Mr. McLawhorn's 26 pages of testimony and his 2 pages of appendix are copied into the record as though given orally from the stand.

(Whereupon, the prefiled direct testimony and appendix of James McLawhorn was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF JAMES S. MCLAWHORN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Testimony of James S. McLawhorn

On Behalf of the Public Staff

North Carolina Utilities Commission

October 20, 2017

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

A. My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to give an overview of the Public Staff's investigation in this case and introduce the other Public Staff witnesses who are presenting testimony. I will also highlight our investigation of DEP's coal ash management practices. Finally, I will provide the Public Staff's recommendations on DEP's request to implement a Job Retention Rider, originally filed in Docket No. E-2, Sub 1153, on August 14, 2017, and consolidated with this general rate case application by Commission Order dated August 29, 2017.

OVERVIEW OF THE PUBLIC STAFF'S INVESTIGATION

Q: PLEASE DESCRIBE THE ROLE OF THE PUBLIC STAFF.

A: The Public Staff is an independent agency created in 1977 to review, investigate and make appropriate recommendations to the North Carolina Utilities Commission with respect to the reasonableness of rates charged, and adequacy of service provided, by public utilities. The Public Staff is composed of approximately 80 professionals, including attorneys, engineers, accountants, economists and analysts, all of whom are dedicated to advocating for utility consumers.

Q: WHO DOES THE PUBLIC STAFF REPRESENT BEFORE THE UTILITIES COMMISSION?

A: Pursuant to G.S. 62-15, the Public Staff intervenes in cases on behalf of the using and consuming public.

Q: WHO IS THE USING AND CONSUMING PUBLIC IN THIS CASE?

A: The using and consuming public in this case is the retail ratepayers of Duke Energy Progress, LLC (DEP). Retail ratepayers include residential, commercial and industrial customers. The using and consuming public does not include the customers of wholesale electric providers such as electric membership cooperatives or municipalities.

Q: HOW DID THE PUBLIC STAFF APPROACH ITS INVESTIGATION IN THIS CASE?

A: The Public Staff approached this case in the same manner as all other cases, which is to gather and analyze the evidence and present recommendations to the Commission on behalf of our clients, the North Carolina retail customers of DEP, that are consistent with the law, rules, regulations, and relevant case precedent. Our investigation explored how technical, investment, accounting, and management decisions were made within the utility and tested whether those decisions were reasonable, prudent, and the lowest reasonable cost option. We approached each issue collectively and reached internal consensus for each position we have put forward in this case. The Public Staff takes its job very seriously and seeks to produce the best possible outcome for consumers within the bounds established for us by the statutes adopted by the North Carolina General Assembly and case law.

Q: PLEASE DESCRIBE THE PUBLIC STAFF'S INVESTIGATION.

A: Upon receipt of DEP's rate case application, the Public Staff immediately organized an internal task force composed of engineers, accountants, attorneys, and economists responsible for investigating all aspects of the case. In total, the Public Staff utilized 27 internal personnel in its investigation, eight of whom will testify in this proceeding. Another 13 professionals in the Consumer Services Division answered phone calls, processed email and written correspondence, and reviewed complaints and inquiries from DEP customers.

The Public Staff also retained the services of five consultants to assist with the investigation and make recommendations regarding highly specialized topics arising in this case. The Public Staff retained the services of Garrett and Moore, P.E. to assist in the evaluation of DEP's coal ash compliance activities, Technical Associates, Inc., to assist in the evaluation of DEP's cost of capital, and William W. Dunkel & Associates to assist in the evaluation of DEP's depreciation and non-nuclear decommissioning studies. In addition, Katherine Fernald and Randy Edwards, former employees of the Public Staff, provided contract accounting services on specialized topics such as excess deferred income taxes and nuclear decommissioning.

The Public Staff reviewed DEP's Form E-1, testimony and exhibits, the testimony of other intervenors, and customer statements filed in the docket, which amounted to thousands of pages of testimony and supporting exhibits. We also reviewed DEP's supplemental filing on September 15, 2017, consisting of 112 pages of testimony and supporting exhibits. The Public Staff served over 165 data requests on DEP and reviewed numerous documents responding to those requests. The Public Staff also reviewed DEP's responses to the data requests of the other intervenors. Public Staff accountants and engineers have reviewed ledger entries and invoices, work orders, change orders, and other supporting documentation. We reviewed over four years of Duke Energy board of director minutes, presentations, and the materials of related board committees.

In addition to reviewing numerous documents and ledger entries, the Public Staff conducted plant site visits to inspect new capital projects that have been placed into service since the last rate case. We also interviewed a number of DEP employees to assist in our understanding of the Company's positions in the case.

Finally, the Public Staff attended the five customer hearings located throughout the state to listen to what customers had to say about this case.

Q. **PLEASE DESCRIBE THE PUBLIC STAFF'S INVESTIGATION INTO DEP'S COAL ASH MANAGEMENT PRACTICES AND COSTS.**

A. The Public Staff's investigation into DEP's coal ash management practices began before DEP filed its rate case application. We knew it would be a huge undertaking, and it has been. As I stated above, we engaged the services of Garrett & Moore to assist us with this investigation. We had access to a database of over 300,000 documents, and sent 26 data requests that resulted in the production of an extremely large number of additional documents. We also reviewed DEP's responses to the data requests of other intervenors and participated in the deposition of DEP's coal ash witness, Mr. Kerin. We interviewed staff at the Department of Environmental Quality in order to enhance our understanding of the coal ash basin closure process and environmental issues resulting from coal ash. Members of Garrett & Moore and our staff visited plant sites and viewed the handling of coal combustion residuals. Public Staff members also visited the Brickhaven facility, which is the disposal site for ash from DEP's Sutton Plant and DEC's Riverbend Plant.

Q: **WHO ARE THE WITNESSES PRESENTING TESTIMONY IN SUPPORT OF THE PUBLIC STAFF'S CASE?**

A: The Public Staff's other witnesses presenting testimony in support of this case are:

1. Michael C. Maness, Director of the Public Staff Accounting Division, who presents accounting adjustments related to DEP's coal ash management practices, including the regulatory treatment of deferred coal ash costs, future coal ash costs, and allocations of coal ash costs. He also discusses adjustments related to the Joint Agency Acquisition Rider, storm costs, meter retirements, and depreciation.
2. Darlene P. Peedin, Public Staff accountant, who presents the accounting and ratemaking adjustments resulting from the Public Staff's investigation of the revenue, expenses, and rate base presented by DEP.
3. Jack L. Floyd, Public Staff engineer, who presents testimony regarding cost of service, Customer Connect, AMI deployment, Power/Forward Carolinas, revenue assignment, and rate design.
4. Dustin R. Metz, Public Staff engineer, who presents testimony regarding Public Staff adjustments related to coal inventory, material and supplies inventory at nuclear generation sites,

and the newly constructed Sutton blackstart combustion turbine project.

5. Jay B. Lucas, Public Staff engineer, who presents testimony regarding Public Staff adjustments related to the Mayo Zero Liquid Discharge System project and DEP's coal ash management practices, including coal ash sales, environmental violations, and CCR and CAMA compliance activities.

6. Scott J. Saillor, Public Staff engineer, who presents testimony regarding operating revenues associated with customer growth.

7. Tommy W. Williamson, Public Staff engineer, who presents testimony regarding DEP's quality of service and Public Staff adjustments regarding storm-related costs and revenues and vegetation management.

8. Vance F. Moore, P.E., President of Garrett & Moore, and Bernie Garrett, P.E., senior engineer with Garrett & Moore, who present testimony regarding the prudence of DEP's coal ash management strategy decisions.

9. David C. Parcell, Principal and Senior Economist of Technical Associates, Inc., who presents his analysis of DEP's cost of capital and capital structure. Witness Parcell makes a

recommendation for an allowed return on equity ("ROE") that is fair to both customers and the company.

10. Roxie McCullar, of William W. Dunkel & Associates who presents her analysis of DEP's depreciation study filed in this case, including adjustments related to terminal net salvage.

Q: PLEASE SUMMARIZE THE ADJUSTMENTS MADE BY THE PUBLIC STAFF TO DEP'S APPLICATION.

A: The Public Staff proposes a number of adjustments that will be discussed in greater detail by the witnesses listed above. The major adjustments proposed by the Public Staff involve the following areas:

- Mayo ZLD cost overruns
- Coal inventory
- Sutton combustion turbine debris issues
- Materials and supplies hold inventory
- ROE and capital structure
- Customer growth
- Customer Connect
- Depreciation and depreciation rates
- Storm-related costs and revenues
- Vegetation management
- Costs to comply with the Coal Ash Management Act and federal Coal Combustion Rule

- Costs associated with coal ash litigation defense, fines, penalties, voluntary payments, settlement payments, and environmental violations
- Costs associated with the federal criminal plea agreement
- Site specific costs related to coal ash disposal activities at Sutton and Asheville

JOB RETENTION RIDER

Q: PLEASE DISCUSS THE COMPANY'S PROPOSED JOB RETENTION RIDER (JRR).

A: As I stated above, DEP filed a petition on August 14, 2017, seeking approval of a Job Retention Rider (JRR-1) in Docket No. E-2, Sub 1153. By Order dated August 29, 2017, the Commission consolidated this matter with the Sub.1142 general rate case. DEP's proposed JRR-1 was filed in accordance with the requirements and guidelines the Commission established in its *Order Adopting Guidelines for Job Retention Tariffs* (JRT Order) dated December 8, 2015, in Docket No. E-100, Sub 73. My review of DEP's filing was reviewed in the context of the JRT Order and the guidelines, conditions, and contract provisions enumerated in the JRT Order.

Q. WHAT ARE THE GUIDELINES AND FILING REQUIREMENTS THAT ARE NECESSARY FOR APPROVAL OF A JRT BY THE NCUC?

Appendix A to the JRT Order (JRT Guidelines), details the guidelines and filing requirements for any proposed JRT. As such, these criteria are applicable to DEP's proposed JRR-1. These guidelines require that the Company show:

1. That the proposed JRT is not unduly discriminatory and is in the public interest;
2. That the proposed JRT is needed and will help avoid a loss of jobs;
3. That the proposed JRT is intended to be temporary; and
4. That the proposed discount covers at least the variable costs and provides some contribution to fixed costs.

The Commission also outlined several conditions that are applicable to individual customers seeking service under a JRT. These conditions include:

1. A customer cannot be served by the JRT in excess of the tariff expiration date, which is a maximum of five years from the date of approval;
2. A customer cannot be served under both a JRT and another economic development or self-generation tariff at the same time;

3. A customer must enter into a JRT contract with the utility, detailing the agreed upon jobs and load to be maintained, termination provisions for failure to maintain, and an affirmation that the discount will be used to achieve job retention;
4. A customer that fails to maintain the agreed upon number of jobs or load, must have its JRT participation discontinued;
5. A customer is required to have at least 12 months of operating experience with the utility;
6. A customer must demonstrate financial viability;
7. A customer must agree to an energy audit;
8. The utility is required to compile a customer-by-customer analysis each year that the JRT is in effect, detailing the impact of the JRT on targeted jobs, electric demand, and energy sales;
9. The Public Staff should have an opportunity to review the customer-by-customer analysis information so that the Public Staff can report to the Commission on the JRT's effectiveness, customer compliance with contract terms, and whether the JRT remains in the public interest; and
10. A customer's eligibility determination shall include use of meaningful, verifiable qualifications establishing that the

customer will achieve job retention and retain customer load, and that the customer will use the discount in doing so.

The Commission's guidelines also provide the opportunity for utilities to seek waivers from these requirements if they are impossible, impractical, or unduly burdensome to the participant or utility, or would not materially aid the Commission in determining whether the proposed rate is just, reasonable, not unduly discriminatory, and in the public interest.

Q. HAVE YOU REVIEWED DEP'S PROPOSED RIDER JRR-1?

A. Yes. DEP stated in its application that it filed the proposed Rider JRR-1 in accordance with the requirements of the JRT Guidelines. I have reviewed the Company's application, proposed tariff, and draft application and agreement (customer contract, including terms and conditions of the proposed Rider JRR-1) to determine compliance with the guidelines, conditions, and contract provisions contained in the JRT Guidelines. I also reviewed the Company's responses to the Public Staff's data request, including workpapers associated with the proposed discount.

Q. DOES THE PROPOSED PILOT RIDER JRR-1 COMPLY WITH THE FOUR JRT GUIDELINES THAT YOU HAVE IDENTIFIED ABOVE?

A. Yes.

Q. PLEASE EXPLAIN HOW THE PROPOSED PILOT RIDER JRR-1 IS NOT UNDULY DISCRIMINATORY AND IN THE PUBLIC INTEREST.

A. The proposed pilot Rider JRR-1 is not unduly discriminatory because it is designed to reach the largest industrial customers who, as stated by the JRT Order, have the unique characteristics of being able to impact other commercial and residential customer classes. When jobs or load leave DEP's system, the economic impact is likely to be felt across all customer classes. The JRT Order recognized that while the criteria for establishing eligibility is not an exact science, the need to retain jobs and electric load must be balanced with the costs of a JRT. DEP's proposal provides for a balancing of benefits and costs between those customers eligible for Rider JRR-1 and those that will bear the reduction in revenues that result from implementation of the rider. Therefore, I do not believe the proposed Rider JRR-1 is unduly discriminatory and I believe it is in the public interest.

Q. HAS DEP DEMONSTRATED THAT RIDER JRR-1 IS NEEDED AND WILL AVOID THE POTENTIAL FOR JOB LOSSES?

A. Yes. DEP's application asserts an "undisputed decline in industrial sales in North Carolina."[1] A review of several recent DEP integrated

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[1] Application at page 6.

resource plans filed with the Commission shows a forecast of slightly positive growth in industrial sales. This growth follows several years of decreasing sales. While the forecasted growth is positive, it is not robust and is not necessarily reflective of all industrial customers or categories of industrial customers. The discount as proposed represents a minimum revenue reduction of 5% for eligible participants and should assist them in maintaining jobs and load in North Carolina.

Q. HAS DEP SHOWN THAT THE JRT WILL BE TEMPORARY?

A. Yes. Rider JRR-1, as filed, is specified to be a five-year pilot. However, as outlined below I believe Rider JRR-1 should be modified to reflect the date of expiration.

Q. HAS DEP DEMONSTRATED THAT THE PROPOSED DISCOUNT AT LEAST COVERS BOTH THE VARIABLE COSTS AND A PORTION OF THE FIXED COSTS OF RIDER JRR-1 PARTICIPANTS?

A. Yes. DEP provided confidential workpapers related to the calculation of the proposed discount and potential impact to revenues associated with Rider JRR-1. My review of those confidential workpapers indicates that the discounted revenue collected from participating customers will likely be greater than the marginal cost to serve all eligible participants.

Q. HAS DEP ADDRESSED IN ITS APPLICATION AND PROPOSED TARIFF EACH OF THE TEN CONDITIONS YOU OUTLINED THAT ARE APPLICABLE TO INDIVIDUAL CUSTOMERS RECEIVING SERVICE UNDER RIDER JRR-1?

A. Yes. My review of the proposed Rider JRR-1 indicates that each of the several conditions I discussed above for Rider JRR-1 has been addressed at least in part; however, I would like to bring four concerns to the Commission's attention.

Q. WHAT IS YOUR FIRST AREA OF CONCERN?

A. My first concern has to do with the availability provision of Rider JRR-1. As filed, the tariff would be available for a customer using electric power "as a principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material of a finished product." My specific concern has to do with the phrase "transportation or preservation of a raw material of a finished product," which the Public Staff understands to refer to pipelines, particularly natural gas pipelines. In order to be eligible to participate in a JRT tariff, the Commission has been clear that there must be a demonstrated need and a way to verify the retention of jobs and load. In other words, there must be a real threat of the loss of jobs or load. The Commission also stated the following regarding eligibility: "...the Commission agrees...that industrial customers or a subset of industrial customers are unique from other customers in that they are not generally tied to any particular location and can more readily or easily relocate."[2]

A gas pipeline is a very different entity than an industrial manufacturing facility, or even a mining operation. Pipelines are fixed investments that are not easily relocated to another area. They must be located in close proximity to refineries and transport their commodity to areas of customer demand. Further, pipelines do not produce a finished product as industrial manufacturing facilities do. In addition, there are many other types of entities not eligible for Rider JRR-1 that have the capability, and are much more likely, to relocate, go out of business, or reduce jobs and load than a gas pipeline. For these reasons, I recommend that the phrase "transportation or preservation of a raw material of a finished product" be eliminated from the Availability section of Rider JRR-1.

Q. WHAT IS YOUR SECOND AREA OF CONCERN?

A. My second area of concern centers around the detail of customer and other JRT-specific data available to the Public Staff for audit, as well as the quality of the review we will be capable of providing to the

[2] Order Adopting Guidelines For Job Retention Tariffs, issued December 8, 2015, page 23.

Commission annually. Section (b)(9) of the JRT Guidelines reads as follows:

> The utility shall be required to compile a customer by customer analysis each year during the duration of the JRT of the impact of the JRT on targeted jobs, electric demand, and electric energy sales, and provide the Public Staff the opportunity to visit and review the information so that the Public Staff can evaluate both the effectiveness of the tariff and customer compliance with the terms of the tariff. The Public Staff shall file a report with the Commission indicating generally, without customer specific information, whether the JRT is effective, that customers were in compliance with their contracts, and whether the JRT remains in the public interest.

In the proposed Rider JRR-1, under "Application Requirements," the customer is required to submit to DEP a written statement or other documentation that demonstrates the customer's plans regarding load shifting and employment, as well as the impact of the cost of electricity on its employment decisions and the load that is at risk. In addition, the customer is required to submit current financial information demonstrating financial viability. Proposed Rider JRR-1 then includes the following statement: "All such statements and documentation shall be confidential, but shall be subject to in camera review <u>by only the Commission</u> upon request." [Emphasis added] While other aspects of Rider JRR-1, as well as the proposed "Application and Agreement" refer to a review by both the "Commission and Public Staff," I am concerned that the above statement in the tariff could cause confusion and misunderstanding, and prevent or delay the Public Staff from performing its duties; therefore, I request that the wording be changed to state that the information shall be subject to review "by only the Commission and Public Staff upon request."

My next area of concern with the review process is that the Commission guidelines direct the Public Staff to annually review and evaluate the JRT for compliance and effectiveness and report its findings to the Commission. I want to bring to the Commission's attention what the customer filing requirements and level of verification planned to be conducted by DEP will require for the Public Staff's annual review and report to the Commission. In response to a Public Staff data request, the Company outlined the level of scrutiny it intended to give the data submitted by JRR-1 customers. Specifically, DEP repeatedly informed the Public Staff in response to questions that it would not review other sources or otherwise verify the information submitted by the customers applying for Rider JRR-1.

Q. WHAT ARE YOUR CONCERNS ABOUT THE PUBLIC STAFF'S JRT ANNUAL REPORT TO THE COMMISSION?

A. My concerns stem from the fact that the Public Staff will be reviewing data that has been collected but not independently verified by DEP, with no ability to verify the information itself. Therefore, our annual report to the Commission will consist primarily of a verification that statements were received by the Company, and that the Company's files contain these statements.

Q. WHAT IS YOUR THIRD AREA OF CONCERN?

A. My third area of concern deals with the requirement in section (b)(12) of the JRT Guidelines that states that participating customers are obligated to use the discount received to retain jobs and any agreed upon load. While there is a statement pertaining to use of the discount for job retention near the end of the proposed Application and Agreement (Contract), I recommend that it be relocated as a fourth bullet point under the section of the Contract entitled "To qualify for the Job Retention Rider the Customer shall:" and restated as follows: "Use the discount received under the Rider to achieve job retention as well as to retain the load at the Customer's operations in North Carolina, as agreed to elsewhere in this Application and Agreement."

Q. WHAT IS YOUR FOURTH AREA OF CONCERN?

A. My fourth concern deals with the effective period for the proposed Rider JRR-1. The Availability section of proposed Rider JRR-1 specifies that it is a "pilot program." A pilot program is not a permanent offering, and as such, it should have a clearly defined beginning and ending; section (b)(3) of the JRT Guidelines provides that the tariff "shall only be in effect for a maximum of five years measured from the date the approved tariff becomes effective." Assuming the Commission approves proposed Rider JRR-1, I recommend that it require DEP to include language in the compliance filing that clearly states that the rider will terminate for all customer participants five years from the date it is first approved by the Commission.

Q. DO YOU HAVE RECOMMENDATIONS CONCERNING THE PROPOSED RECOVERY OF ANY DISCOUNTED REVENUE AS PROPOSED BY THE COMPANY?

A. Yes. I disagree with the Company's proposal for deferral accounting between rate cases of the discounted revenue, and its proposal for sharing of the discount between DEP's customers and shareholders. I also have a recommendation for allocation of any revenue impacts resulting from the rider.

DEP has specifically requested deferral, with interest, of any costs associated with proposed Rider JRR-1 that exceed a one-time shareholder contribution of $3.5 million. The Company's request would defer, with interest, the amount of any discount provided to participants from now through the test year period of a future general rate case, minus $3.5 million. The resulting balance would be incorporated into rates in a future rate case. DEP estimated the rate impact on residential customers, assuming participation by all eligible customers, to be 67 cents per month for usage of 1,000 kWh.

Q. WHY DO YOU DISAGREE WITH DEP'S REQUEST FOR DEFERRAL ACCOUNTING BETWEEN RATE CASES OF ANY REVENUE DISCOUNT THAT RESULTS FROM RIDER JRR-1?

A. I believe that deferral is inappropriate because accounting deferrals are typically reserved for unusual costs. A rate discount is not a cost. Instead, the discount occurs because DEP has offered a new rate option to qualifying customers, much as it already offers multiple rate options to its customers. Customers have the right, as they always have, to choose among all rate options for which they qualify and are most financially advantageous to them. If a customer finds that moving to a time-of-use rate schedule, for which it qualifies, results in a lower bill, DEP is not allowed, nor should it be allowed, to defer any revenue differential until the next rate case. Likewise, if customer usage changes between rate cases such that revenue is generated that exceeds DEP's cost to provide service, and thus increases its profitability, DEP is not required to defer those revenues under the guise of excessiveness and then refund them at the time of its next general rate case.

Instead, the revenue impact from a JRT-type tariff is more analogous to the traditional rate case adjustment made for customer migration.

In a general rate case proceeding, when DEP adjusts revenues for rate design purposes to recognize the revenue impacts from the migration of customers from one rate schedule to another the Public Staff has supported, and the Commission has historically accepted this adjustment. In recent cases, the revenue adjustment assumption has been that 50% of potential revenue impacts from customer rate schedule migration will be realized, and a corresponding revenue adjustment has been allowed. The Company and the Public Staff have found this one-time assumption of 50% migration to be a reasonable approximation of what actually transpires. Thus, my recommendation is that the Commission direct DEP to make a one-time rate design revenue adjustment in this case for the effects of proposed Rider JRR-1, with no deferral of the rate discount between general rate cases. For this case, DEP should be required to recalculate the potential revenue adjustment cited in its original application ($24.8 million) by removing pipeline customers from Rider JRR-1 eligibility. Next, DEP should reduce that amount by $3.5 million (shareholder contribution), and then take 50% of the remaining net amount as an adjustment to revenues for rate design purposes.

Q. WHY DO YOU DISAGREE WITH DEP'S PROPOSED SHARING OF THE RATE DISCOUNT BETWEEN CUSTOMERS AND SHAREHOLDERS?

A. DEP has estimated that Rider JRR-1 could produce a discounted annual revenue impact of approximately $25 million as proposed. As such, DEP has offered that its shareholders account for $3.5 million of this discount one time only, with ratepayers responsible for the balance in the first year, and the full amount in subsequent years. I have already stated that the Commission should not approve the Company's requested deferral accounting for the rate discount, but should instead make a one-time revenue adjustment for estimated customer migration, applying the historically utilized 50% migration factor; however, I recommend that DEP's shareholders should be responsible for the first $3.5 million on an annual basis while the Rider is in effect; thus the 50% migration adjustment would only apply to the remaining balance after the shareholder portion has been deducted.

I believe my recommendation represents a fair sharing of revenue credit responsibility between DEP's customers and shareholders. While customers benefit from jobs, and resulting load and revenue retention from Rider JRR-1 eligible customers, shareholders will also benefit. Just as customers will pay a portion of the discounted revenue credit on an annual basis under my recommendation to use the 50% migration adjustment, the shareholder benefit will not end after one year as is proposed by the Company in its filing. Thus, an ongoing sharing of responsibility between customers and shareholders is both fair and appropriate.

Q. DOES THE COMPANY HAVE A SPECIFIC PROPOSAL TO ALLOCATE THE IMPACTS OF THE RATE DISCOUNT AMONG CUSTOMERS AND CLASSES OF CUSTOMERS?

A. DEP makes no such recommendation in its application. In response to a Public Staff data request, DEP stated the following: "No decision regarding cost recovery has been made at this time. If the Company adopts the approach proposed by Duke Energy Progress in its 2012 rate case, the revenue reduction would be recovered using an energy allocator from all North Carolina retail customers." The Public Staff finds the approach proposed in 2012 to be reasonable and requests that the Commission direct that any recovery of a discounted revenue credit be recovered from all North Carolina retail customers in all customer classes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

JAMES S. MCLAWHORN

I graduated with honors from North Carolina State University with the Bachelor of Science Degree in Industrial Engineering in May of 1984. I received the Master of Science Degree in Management with a finance concentration from North Carolina State University in December of 1991. While an undergraduate, I was selected for membership in both Tau Beta Pi and Alpha Pi Mu engineering honor societies.

I began my employment with the Public Staff Communications Division in June of 1984. While with the Communications Division, I testified before the Commission in general rate proceedings regarding matters of telephone quality of service.

In September of 1987, I was employed by GTE-South as an engineer in the Capital Recovery Department. I was responsible for analysis and recommendations to Company management regarding appropriate depreciation rates for recovery of the Company's capital investments.

I began my employment with the Electric Division of the Public Staff in November of 1988. I assumed my present position as Director of the Electric Division in October of 2006. It is my responsibility to supervise and make policy recommendations on all electric utility matters before the Commission.

I have testified previously before the Commission in numerous proceedings including Duke Energy Carolinas, LLC's Rate Cases Docket No. E-7, Subs 487, 909 and 989; Duke Energy Progress, LLC's Rate Case Docket No. E-2, Sub 1023; Virginia Electric and Power Company's Rate Cases Docket No. E-22, Subs 314, 333, 412, and 532; New River Light and Power Company Rate Cases Docket No. E-34, Subs 28 and 32; Nantahala Power and Light Company Rate Case Docket No. E-13, Sub 157; in the Application of Dominion North Carolina Power to join PJM in Docket No. E-22, Sub 418; in Duke Power Company's request to merge with Cinergy Corporation in Docket No. E-7, Sub 795; in Duke Energy Carolinas, LLC's request for approval of its Save-A-Watt cost recovery model in Docket No. E-7, Sub 831; and, in the Generic Investigation into Section 111 of the 1992 Energy Policy Act in Docket No. E-100, Sub 69.

BY MS. DOWNEY:

Q. Mr. McLawhorn, did you also prepare and cause to be filed on November 22, 2017, supplemental testimony consisting of four pages?

A. Yes.

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

A. No, I don't.

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

A. Yes, they would.

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

CHAIRMAN FINLEY: Mr. McLawhorn's four pages of supplemental testimony is copied into the record as though given orally from the stand.

(Whereupon, the prefiled supplemental testimony of James McLawhorn was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))))	SUPPLEMENTAL TESTIMONY OF JAMES S. MCLAWHORN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Supplemental Testimony of James S. McLawhorn

On Behalf of the Public Staff

North Carolina Utilities Commission

November 22, 2017

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

A My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Public Staff – Electric Division.

Q. **DID YOU FILE DIRECT TESTIMONY IN THIS CASE ON OCTOBER 20, 2017?**

A. Yes.

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

A. The purpose of my supplemental testimony is to support the Agreement and Stipulation of Partial Settlement (Stipulation) between Duke Energy Progress, LLC (DEP or the Company), and the Public Staff (Stipulating Parties) regarding certain issues related to the Company's pending application for a general rate increase.

Q. WHAT BENEFITS DOES THE STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, among the most important benefits provided by the Stipulation are:

(a) A significant reduction in the Company's proposed revenue increase in this proceeding; and

(b) The avoidance of protracted litigation by the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

Q. ARE THERE ANY AREAS ABOUT WHICH THE STIPULATING PARTIES DID NOT REACH AGREEMENT?

A. Yes. The Stipulating Parties did not reach agreement regarding recovery of coal ash costs, recovery of storm costs, and certain aspects of the proposed Job Retention Rider. The Public Staff fully supports its filed positions on these particular issues, and intends to demonstrate the appropriateness and reasonableness of its positions through litigation in this case.

Q. DOES THIS COMPLETE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

BY MS. DOWNEY:

Q. Moving to you, Ms. Peedin. Would you please state your name, business address, and present position?

A. (Darlene Peedin) Darlene P. Peedin, 430 North Salisbury Street, Raleigh, and I'm an accounting manager with the electric section with the Public Staff accounting division.

Q. Ms. Peedin, how long have you been with the Public Staff?

A. Twenty-seven years.

Q. Did you prepare and cause to be filed, on October 20, 2017, direct testimony in this case consisting of 32 pages, 1 appendix, and 3 exhibits with schedules?

A. Yes, ma'am.

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

A. I do.

Q. Would you please tell us what that is?

A. Okay. On page 30, line 18, the date should read May 13, 2014.

Q. Okay. Ms. Peedin, with that correction, if the same questions were asked of you today, would your answers be the same?

A. Yes.

MS. DOWNEY: Mr. Chairman, I move that the direct testimony and appendix of Ms. Peedin be copied into the record as if given orally from the stand, and that her exhibits be premarked as filed.

CHAIRMAN FINLEY: Ms. Peedin's direct prefiled testimony consisting of 32 pages and her one appendix are copied into the record as if given orally from the stand, and her two exhibits are marked for identification as premarked in the filing.

(Whereupon, Peedin Exhibits 1 and 2 were identified as marked when prefiled.)

(Whereupon, the prefiled direct testimony and one appendix of Darlene Peedin was copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of		
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF DARLENE P. PEEDIN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Testimony of Darlene P. Peedin

On Behalf of the Public Staff

North Carolina Utilities Commission

October 20, 2017

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

A. My name is Darlene P. Peedin. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Accounting Manager-Electric Section with the Accounting Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the accounting and ratemaking adjustments I am recommending, as well as those recommended by other Public Staff witnesses, as a result of the

Public Staff's investigation of the revenue, expenses, and rate base presented by Duke Energy Progress, LLC (DEP or the Company) in support of its June 1, 2017, request for $477,495,000 in additional North Carolina Retail revenue. On September 15, 2017, DEP filed supplemental testimony and exhibits that detailed a $57,958,000 reduction in its request for additional North Carolina retail revenue. The impact of this supplemental filing reduced the total Company proposed increase to $419,537,000.

Q. WHAT REVENUE INCREASE IS THE PUBLIC STAFF RECOMMENDING?

A. Based on the level of rate base, revenue, and expenses annualized at December 31, 2016, with certain updates, the Public Staff is recommending an increase in annual operating revenue of $2,783,000.

Q. MS. PEEDIN, PLEASE DESCRIBE THE SCOPE OF YOUR INVESTIGATION INTO THE COMPANY'S FILING.

A. My investigation included a review of the application, testimony, exhibits, and other data filed by the Company, an examination of the books and records for the test year, and a review of the Company's accounting, end-of-period, and after-period adjustments to test year revenue, expenses, and rate base. The Public Staff has also conducted extensive discovery in this matter, including the review of numerous data responses provided by the Company in response to data requests, participation in conference calls with the Company, on-site visits to review documents and interview personnel, and tours of the Company's plants.

Q. PLEASE BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE ISSUES IN THIS CASE.

A. Each Public Staff witness will present testimony and exhibits supporting his or her position and recommend any appropriate adjustments to the Company's proposed rate base and cost of service. My exhibits reflect and summarize these adjustments, as well as the adjustments I recommend.

Q. PLEASE GIVE A MORE DETAILED DESCRIPTION OF THE ORGANIZATION OF YOUR EXHIBITS.

A. Schedule 1 of Peedin Exhibit 1 presents a reconciliation of the difference between the Company's requested increase of $477,495,000 and the Public Staff's recommended increase of $2,783,000.

Schedule 2 presents the Public Staff's adjusted North Carolina retail original cost rate base. The adjustments made to the Company's proposed level of rate base are summarized on Schedule 2-1 and are detailed on backup schedules.

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. Schedule 3-1 summarizes the Public Staff's adjustments, which are detailed on backup schedules.

Schedule 4 presents the calculation of required net operating income, based on the rate base and cost of capital recommended by the Public Staff.

Schedule 5 presents the calculation of the required increase in operating revenue necessary to achieve the required net operating income. This revenue increase is equal to the Public Staff's recommended increase shown at the bottom of Schedule 1.

Peedin Exhibit 2 sets forth the calculation of an annual EDIT Rider to be in effect for two years

Q. **MS. PEEDIN, WHAT ADJUSTMENTS TO THE COMPANY'S COST OF SERVICE DO YOU RECOMMEND?**

A. I am recommending adjustments in the following areas:

1) Updated Net Plant and Depreciation Expense
2) Update for New Depreciation Rates
3) Updated Revenues and Non-Fuel Variable Operation and Maintenance (O&M) Expenses
4) Mayo Zero Liquid Discharge (ZLD)
5) Sutton Blackstart Combustion Turbine (CT) Project
6) Cash Working Capital Under Present Rates

7) Coal Inventory

8) Effect of Inflation on Non-Fuel O&M Expenses

9) Harris Units 2 and 3 COLA Amortization

10) End of Life Reserve for Nuclear Materials and Supplies

11) Customer Growth

12) Hurricane Matthew Revenue

13) Executive Compensation and Benefits

14) Board of Directors Expenses

15) Incentive Plans

16) Aviation Expenses

17) Outside Services

18) Removal of Costs to Achieve the Duke-Piedmont Merger

19) Allocations from DEBS

20) Lobbying Expenses

21) Distribution Vegetation Management

22) Customer Connect

23) Storm Expenses

24) Sponsorships and Donations

25) Interest Synchronization

26) Cash Working Capital Effect of Increase

27) Excess Deferred Income Taxes (EDIT)

Q. WHAT ADJUSTMENTS RECOMMENDED BY OTHER PUBLIC STAFF WITNESSES DO YOUR EXHIBITS INCORPORATE?

A. My exhibits reflect the following adjustments recommended by other Public Staff witnesses:

1) The recommendations of Public Staff witness Parcell of Technical Associates, Inc. regarding the capital structure,

embedded cost of long-term debt, and return on common equity.

2) The recommendations of Public Staff witness Floyd regarding Customer Connect.

3) The recommendations of Public Staff witness Metz regarding Coal Inventory, the Sutton Blackstart CT Project, and Nuclear Materials and Supplies Inventory.

4) The recommendations of Public Staff witness Lucas regarding the Mayo ZLD Project.

5) The recommendations of Public Staff witness McCullar of William Dunkel and Associates regarding the Company's depreciation study.

6) The recommendations of Public Staff witness Williamson regarding imputed revenues related to Hurricane Matthew and Vegetation Management.

7) The recommendations of Public Staff witness Maness regarding deferred and ongoing environmental costs and the Company's storm deferral request.

8) The recommendation of Public Staff witness Saillor regarding customer growth.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.

A. My adjustments are described below.

UPDATED NET PLANT AND DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN HOW PLANT, ACCUMULATED DEPRECIATION AND DEPRECIATION EXPENSE ARE RELATED.

A. As the Company places new plant into service, it increases its rate base. Upon being placed in service, the plant begins to depreciate, and depreciation expense is recorded each accounting period (and recovered from ratepayers) as the plant is used in providing service. The cumulative amount of depreciation expense is reflected on the balance sheet as accumulated depreciation, which is deducted from the original cost of the plant to determine net plant. Net plant (i.e., total plant, net of accumulated depreciation) is used to calculate the rate base on which the Company is allowed to earn a return, while depreciation expense is an input in the calculation of net operating income.

Q. PLEASE EXPLAIN THE COMPANY'S COMPUTATION OF NET PLANT.

A. The Company began its calculation of net plant with the plant and accumulated depreciation amounts recorded at the end of December 31, 2016 (the test year in this case), and then updated for actual plant additions through August 31, 2017, including the annual level of depreciation on the plant additions as well as the matching amount of accumulated depreciation. The Company excluded additions related to NCEMPA [which are recoverable through the Joint Agency Asset Rider (JAAR)], and customer growth related additions.

Q. PLEASE EXPLAIN HOW YOU HAVE COMPUTED NET PLANT.

A. My calculation begins with plant, accumulated depreciation, and net plant with the Company's actual per books plant in service and accumulated depreciation amounts as of August 31, 2017, which include rate base customer growth-related actual plant additions.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN YOUR AMOUNT OF NET PLANT AND THE COMPANY'S AMOUNT.

A. I have reflected $158 million less net plant than the Company, primarily because I have updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year (December 31, 2016) and the update period ending August 31, 2017. Because I have updated plant and accumulated depreciation to reflect the Company's actual August 31, 2017, per books amounts, I have also considered the effect of normal retirements on the computation of depreciation expense. Pursuant to the FERC Uniform System of Accounts, normal retirements of plant reduce plant and accumulated depreciation by offsetting amounts, and thus do not affect the amount of net plant reflected as a component of rate base. If retirements are not properly reflected in the amount of plant used to compute depreciation expense, depreciation expense will be overstated. Because the Company has not properly reflected the effect of normal retirements, its computation of depreciation expense includes depreciation expense on plant that was retired as of August 31, 2017 and consequently is overstated.

Q. BY MAKING THIS ADJUSTMENT TO UPDATE ACCUMULATED DEPRECIATION FOR DEPRECIATION EXPENSE THAT HAS BEEN RECOVERED FROM RATEPAYERS SINCE THE END OF THE TEST PERIOD, IS THE PUBLIC STAFF CHANGING THE TEST PERIOD?

A. No. Consistent with G.S. 62-133, we have used the historic test year to determine the cost of service for DEP. When justified, we have updated expenses, revenues, and investment to reflect the Company's most recent ongoing levels for these items, based on actual known and measurable changes occurring after the test year, just as DEP did in its initial and supplemental testimony. The costs of the plant additions that the Company included are known and measurable, as are the plant retirements that have occurred and the depreciation that has been recovered from ratepayers since the end of the test period. Including only plant additions and omitting changes in accumulated depreciation, as the Company has done, fails to properly take into account the relationships among plant, depreciation expense and accumulated depreciation, as well as the relationship between net plant and other cost of service items. The Public Staff updated plant and accumulated depreciation to reflect actual per books amounts as of August 31, 2017, because that date represents the same point in time that the Public Staff used to update customer growth.

While the Public Staff's adjustment to accumulated depreciation is beyond the test year, it recognizes and maintains its relationship with plant and other cost of service items and is permitted by G.S. 62-133(c) and (d). G.S. 62-133(c) provides that the Commission shall consider evidence of changes in costs, revenues, or rate base after the test year, while G.S. 62-133(d) requires the Commission to consider all material facts to allow it to set just and reasonable rates. The changes in plant, depreciation expense, and accumulated depreciation since the test year are exactly the type of changes and material facts that the Commission must consider pursuant to G.S. 62-133(c) and (d).

The adjustment I recommend is consistent with the Commission's past treatment of comprehensive plant updates beyond the end of the test year. Adjustments like this have been consistently approved by the Commission in rate cases for natural gas utilities since the

1990's and were used by Dominion Energy North Carolina in its most recent general rate cases.[1]

UPDATE FOR NEW DEPRECIATION RATES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO DEPRECIATION EXPENSE TO REFLECT NEW DEPRECIATION RATES.

A. Based on the recommendations of Public Staff witness McCullar, I have made an adjustment to adjust depreciation expense to reflect her recommended depreciation rates.

UPDATED REVENUES AND NON-FUEL VARIABLE O&M EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UPDATE REVENUES AND VARIABLE NON-FUEL O&M EXPENSES.

A. As part of my update to plant and related items, I have updated revenues to reflect the effect of customer growth as of August 31, 2017, based on the recommendation of Public Staff witness Saillor. I have made a corresponding adjustment for the increase in customer-related O&M expenses that result from the additional customers. I have also made corresponding adjustments to fuel and

[1] Per Commission Orders in Public Service Company of North Carolina, Inc. Docket No. G-5, Sub 565; Piedmont Natural Gas Company, Inc. Docket No. G-9, Sub 631; Dominion North Carolina Power Docket Nos. E-22, Sub 479 and Sub 532.

energy-related non-fuel O&M expenses for the additional kilowatt hours resulting from increased sales.

MAYO ZLD

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE CERTAIN COSTS RELATED TO THE MAYO ZLD PROJECT.

A. I have incorporated an adjustment to include the recommendation of Public Staff witness Lucas to disallow certain costs related to the Mayo ZLD Project. I have also made corresponding adjustments to depreciation expense and accumulated depreciation to reflect his recommendation.

SUTTON BLACKSTART CT PROJECT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE CERTAIN COSTS RELATED TO THE SUTTON BLACKSTART CT PROJECT.

A. I have incorporated an adjustment to include the recommendation of Public Staff witness Metz to remove costs related to the Sutton Blackstart CT Project debris contamination. I have also made corresponding adjustments to depreciation expense and accumulated depreciation to reflect his recommendation.

CASH WORKING CAPITAL UNDER PRESENT RATES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL UNDER PRESENT RATES.

A. The Company computed cash working capital using the lead-lag study method and then adjusted it to fully reflect all of the Company's proposed adjustments, before the amount of the proposed rate increase. I have likewise adjusted cash working capital under present rates to reflect all of the Public Staff's adjustments, in accordance with the Commission's Order in Docket No. M-100, Sub 137. This cash working capital adjustment is reflected on Schedule 2-1 and incorporates the effect of the Public Staff adjustments, before the rate increase, on lead-lag study cash working capital.

COAL INVENTORY

Q. PLEASE EXPLAIN THE ADJUSTMENT TO COAL INVENTORY.

A. As discussed by Public Staff witness Metz, coal inventory should be reduced from the 40-day target at 100% full load burn, used by the Company in its Application, to a target level of 30 days at 70% full load burn.

EFFECT OF INFLATION ON NON-FUEL O&M EXPENSES

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE COMPANY'S INFLATION ADJUSTMENT?

A. The Company made an adjustment to annual non-labor, non-fuel O&M costs, to reflect the increase in costs during the test year that occurred due to the effect of inflation. I have adjusted the inflation factor through August 31, 2017, to coordinate with other items updated through that same point in time. I have also modified the Company's inflation adjustment to reflect the Public Staff's adjustment to include variable O&M expenses for changes in customer growth and the removal of aviation expenses, Board of Directors (BOD) expenses, outside services expenses, and sponsorships and donations.

HARRIS UNITS 2 AND 3 COLA AMORTIZATION

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO THE COMPANY'S AMORTIZATION OF CERTAIN COSTS INCURRED FOR THE DEVELOPMENT OF UNITS 2 AND 3 OF THE HARRIS NUCLEAR STATION.

A. In Docket No. E-2, Sub 1035, the Commission approved the Company's petition to defer certain capital costs incurred for the development of Units 2 and 3 of the Harris Nuclear Station. The Commission allowed the amortization of certain of these costs, on the condition that the amortization period should not exceed the period during which the costs were incurred or five years, whichever is greater. The Company incurred the development costs over an eight year period; however, DEP used a period of five years in its amortization adjustment in this case. The Public Staff has adjusted the amortization period to eight years, to reflect the period over which the costs were incurred. It is my understanding that the Company agrees with an eight-year amortization period.

END OF LIFE RESERVE FOR NUCLEAR MATERIALS AND SUPPLIES

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT FOR THE END OF LIFE RESERVE FOR MATERIALS AND SUPPLIES.

A. Based on the testimony of Public Staff witness Metz, I have made an adjustment to reflect his recommendation to remove certain items from inventory.

CUSTOMER GROWTH

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR CUSTOMER GROWTH.

A. I have adjusted customer growth to reflect the recommendations of Public Staff witness Saillor.

HURRICANE MATTHEW REVENUE

Q. WHAT ADJUSTMENT DOES THE PUBLIC STAFF RECOMMEND RELATED TO HURRICANE MATTHEW REVENUE?

A. As discussed by Public Staff witness Williamson, the Company made an adjustment to increase revenues to reflect the estimated net lost revenues from residential and commercial customers as a result of Hurricane Matthew. Because industrial customers were also affected by the hurricane, the Public Staff has modified this adjustment to include the net lost revenues from the industrial class of customers. I have included an adjustment to reflect witness Williamson's recommendation.

EXECUTIVE COMPENSATION AND BENEFITS

Q. WHAT ADJUSTMENT HAVE YOU MADE TO EXECUTIVE COMPENSATION AND BENEFITS?

A. The Company made an adjustment to remove 50 percent of the compensation of the four Duke Energy executives with the highest level of compensation allocated to DEP in the test period. My adjustment includes the removal of 50 percent of the compensation of an additional executive. The premise of including the compensation of the top five Duke Energy executives, as opposed to the top four executives as the Company has done, is to reflect the fact that the additional executive's duties and compensation encompass a substantial amount of activities that are closely linked to shareholder interests, just as in the case of the other four executives.

I have also made an adjustment to remove 50 percent of the benefits associated with these top five Duke Energy executives. This adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers. The Public Staff believes that it would be inconsistent to remove the compensation of these five executives without also removing the benefits related to that compensation.

Q. IS YOUR RECOMMENDATION BASED ON THE PREMISE THAT THE COMPENSATION AND BENEFITS OF THE EXECUTIVE OFFICERS YOU HAVE SELECTED IS EXCESSIVE OR SHOULD BE REDUCED?

A. No. This recommendation is based on the Public Staff's belief that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests, which are not always the same as those of ratepayers. Officers have fiduciary duties of care and loyalty to shareholders, but not to customers. Consequently, the Company's executive officers are obligated to direct their efforts not only to minimizing the cost and maximizing the reliability of DEP's service to customers, but also to maximizing the Company's earnings and the value of its shares. It is reasonable to expect that management will serve the shareholders as well as the ratepayers; therefore, a portion of management salary and benefits should be borne by the shareholders.

BOARD OF DIRECTORS (BOD) EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO BOD EXPENSES.

A. I have made an adjustment to remove 50 percent of the expenses associated with the BOD of Duke Energy Corporation that have been allocated to DEP. The expenses allocated to DEP encompass the BOD's compensation, insurance, and other miscellaneous expenses. The premise of this adjustment is closely linked to the premise of the adjustment made by the Public Staff related to executive compensation. We believe that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating those individuals with a fiduciary duty is to protect the interests of shareholders, which may differ from the interests of ratepayers. Further, Directors' and Officers' liability insurance, while a necessary expense for a corporation, has been utilized to defend the Board in suits brought by shareholders regarding issues such as the merger with Duke Energy Corporation and coal ash. It is appropriate for shareholders to share the cost of the insurance with ratepayers.

INCENTIVE PLANS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR THE COMPANY'S LONG AND SHORT TERM INCENTIVE PLANS.

A. DEP offers two incentive plans to its employees: the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). The STIP is offered to all employees, including executives. The LTIP is offered to employees at the Director level and above. Approximately 700 employees of Duke Energy Corporation qualify for the LTIP.

The STIP consists of goals set and approved by the BOD for a one year term. In 2016, the test year in this case, the goals consisted of Earnings per Share (EPS), Operational Excellence, Customer Satisfaction, and Safety, as well as team and individual goals. The LTIP goals consist of Performance Shares, which are further categorized between EPS and Total Shareholder Return (TSR), and Restricted Stock Units (RSU). Both offerings are set and approved by the BOD for a three-year period.

The Company's payout of STIP is based on the achievement of targets at minimum, target and maximum levels. During the test year, the Company included an adjustment to reduce the STIP from the 2016 payout level to the 2017 target level. With regard to LTIP, the Company made an adjustment to remove the 2016 accruals and replace them with 2017 target accruals. I have adjusted the allowable costs of STIP to exclude the incentive accruals that were based on the EPS metric. I have also adjusted the allowable LTIP costs to exclude the Performance Shares, which include the EPS and TSR metrics. The Public Staff believes that the incentives related to EPS and TSR should be excluded because they provide a direct benefit to shareholders rather than to ratepayers. These costs should be borne by shareholders.

AVIATION EXPENSES

Q. WHAT ADJUSTMENT DO YOU RECOMMEND RELATED TO AVIATION EXPENSES?

A. The Company made an adjustment to O&M expenses to remove an amount for corporate aviation. The Public Staff made a further adjustment after investigating the aviation expenses charged to DEP during the test year. The aviation expenses are incurred by Duke Energy Corporation, and then a portion is allocated to DEP through the use of a corporate allocation factor. Based on the Public Staff's review of flight logs, the corporate aircraft are available for use by Duke Energy Corporation's Chief Executive Officer (CEO) and her staff. I recommend that certain expenses allocated to DEP be removed due to the nature of the flights involved. Some of these flights appear to be unrelated to the provision of utility service; in other instances, the costs of the flights have been incorrectly allocated; and in other cases, the Company has not justified the costs of using Company-owned aircraft rather than purchasing tickets for commercial flights.

OUTSIDE SERVICES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO OUTSIDE SERVICES.

A. During 2016, the test year in this case, the Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEP by Duke Energy Business Services (DEBS) as well as those incurred by DEP directly. Our investigation revealed charges that were related to legal services for coal ash and groundwater issues related to coal ash. I have removed these expenses from O&M in the test period based on the advice of counsel. We also found certain expenses that were allocated to DEP that should have been directly assigned to other jurisdictions, as well as costs allocated to DEP for the Duke-Piedmont merger. The costs allocated to DEP for the Duke-Piedmont merger are discussed in the next section of my testimony. DEP ratepayers should be charged only the reasonable costs of providing electric service to North Carolina retail customers.

REMOVAL OF COSTS TO ACHIEVE DUKE-PIEDMONT MERGER

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO COSTS TO ACHIEVE THE MERGER.

A. On September 29, 2016, in Docket No. E-7, Sub 1100, Docket No. E-2, Sub 1095, and Docket No. G-9, Sub 682, the Commission issued its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order), which approved the merger between Duke Energy Corporation and Piedmont Natural Gas (PNG). Ordering paragraph 7(b) of the Merger Order, which addresses the ratemaking treatment of costs incurred to achieve the merger, states (emphasis added):

> DEC, DEP, and Piedmont may request recovery through depreciation or amortization, and inclusion in rate base, as appropriate and in accordance with normal ratemaking practices, their respective shares of **capital costs associated with achieving merger savings** [emphasis added], such as system integration costs and the adoption of best practices, including information technology, provided that such costs are incurred no later than three years from the close of the merger and result in quantifiable cost savings that offset the revenue requirement effect of including the costs in rate base. Only the net depreciated costs of such system integration projects at the time the request is made may be included, and no request for deferrals of these costs may be made.

On October 4, 2017, Duke Energy Corporation filed a letter indicating that both it and Piedmont accepted and agreed to all the terms, conditions, and provisions of the Merger Order, including the Regulatory Conditions and Code of Conduct. During the test year in this case, DEP has included in operating expenses approximately $3.8 million on a North Carolina retail basis that it identified as systems and transition costs to achieve merger savings.

DEP has not requested recovery of these costs in rate base, but instead has chosen to include them in O&M expenses. Because DEP did not request recovery of these costs "through depreciation or amortization, and inclusion in rate base," as ordering paragraph 7(b) requires, the Company is prohibited from recovering them.

ALLOCATIONS FROM DEBS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ALLOCATIONS FROM DEBS.

A. DEBS is the company that provides services to various affiliated entities of Duke Energy Corporation. The affiliated entities have a Cost Allocation Manual (CAM) that documents the guidelines and procedures for allocating costs between the entities to ensure that one entity does not subsidize another. During the test year, Duke Energy acquired PNG, and the merger was approved by the Commission on September 29, 2016. This change, along with updates related to other affiliated entities, has caused the DEP allocation factors to decrease on a going-forward basis. As a result, I have made an adjustment to reflect the fact that O&M expenses allocated to DEP from DEBS will be less going forward.

LOBBYING EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSMTENT TO LOBBYING EXPENSES.

A. The Company made an adjustment to remove some lobbying expenses from the test year. I have further adjusted O&M expenses to remove additional lobbying costs. In determining what costs should be removed, I applied the "but for" test for reporting lobbying costs as used in a Formal Advisory Opinion of the State Ethics Commission dated February 12, 2010. The Commission recognized at pages 70-71 of its 2012 Dominion North Carolina Power order in Docket No. E-22, Sub 479, that lobbying included not only employees' direct contact with legislators, but also other activities preparing for or surrounding lobbying that would not have been conducted but for the lobbying itself. In applying this test, I removed O&M expenses associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line.

DISTRIBUTION VEGETATION MANAGEMENT

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO DISTRIBUTION VEGETATION MANAGEMENT.

A. I have made an adjustment to distribution vegetation management expenses (VM) to include a reasonable level for the test period in this case. Vegetation Management for distribution and transmission is further discussed in the testimony of Public Staff witness Williamson. This adjustment to distribution VM is calculated based on the ongoing level of the annual target distribution VM miles and the test year VM actual cost per mile. In 2015, Duke Energy engaged a consultant to conduct a tree species frequency and regrowth study for approximately 90% of its distribution VM areas in the DEP service territory. As a result of this study, DEP decided to modify its target cycle from 6 to 7 years for non-urban miles. Adjusting the target cycle to a 7 years will reduce the amount of production dollars needed by the Company to maintain its VM program. The actual cost per mile used in the calculation is consistent with the cost per mile experienced by DEP in prior years. The level of VM costs remaining in O&M expenses is adequate funding for maintaining a prudent distribution VM program.

CUSTOMER CONNECT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CUSTOMER CONNECT.

A. In this case, the Company included an amount of forecasted costs that it expects to incur during the 2018-2020 time frame related to its

Customer Connect project. As stated in the Company's testimony, the Customer Connect project is currently planned to be in service in 2021 and will replace the Company's current billing system. I have made an adjustment to remove the forecasted amounts the Company plans to spend between 2018 and the in-service date. The rationale for this adjustment is that the system is in the analytics stage. Specifically, the Company is in the process of gathering customer data to build and develop a platform to enhance customer interactions with the Company and the system has not been placed in service. Based on my understanding of this project, full functionality of this project for DEP is not expected until the summer of 2021. Public Staff witness Floyd will provide further testimony on Customer Connect.

STORM EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO STORM EXPENSES AND STORM DEFERRAL REQUESTED BY THE COMPANY.

A. The Company made an adjustment to normalize North Carolina retail O&M expenses for storm expenses. My adjustment to the Company's level of storm expenses reflects a normal level of storm expenses based on the average annual storm expenses (excluding base labor costs) incurred by the Company over a ten-year period, adjusted for inflation. I have also reflected a ten-year average of storm expenses to recognize the Public Staff's position, set forth in Docket No. E-2, Sub 1131, that abnormal storm expenses are those outside "the usual range of volatility, or range of fluctuation, of the expense." The level of abnormal storm expenses has been updated in this case for actual changes to the expense amount. Public Staff witness Maness will be providing testimony regarding the Company's deferral request.

SPONSORSHIPS AND DONATIONS

Q. WHAT ADJUSTMENT HAVE YOU MADE FOR SPONSORSHIPS AND DONATIONS?

A. I have adjusted O&M expenses to remove amounts charged to O&M expense for sponsorships and charitable donations. Specifically, I have excluded from expenses amounts paid to the U.S. Chamber of Commerce and other chambers of commerce. These expenses should be disallowed because they do not represent actual costs of providing electric service to customers.

INTEREST SYNCHRONIZATION ADJUSTMENT

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. The Company adjusted income tax expense to reflect interest synchronization with its proposed capital structure, cost of debt and rate base. I have also adjusted income tax expense to reflect the deduction of the pro forma level of interest resulting from the application of the Public Staff's recommended return and capital structure to its recommended rate base.

<u>CASH WORKING CAPITAL EFFECT OF RATE INCREASE</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL FOR THE PROPOSED INCREASE.

A. The cash working capital lead-lag effect of the proposed revenue increase as recommended by the Public Staff has been calculated on Peedin Exhibit 1, Schedule 2-1(g).

REMOVE EDIT REFUND FROM BASE RATES

<u>AND ESTABLISH AN EDIT RIDER</u>

Q. PLEASE EXPLAIN THE EDIT RIDER.

A. In this case, the Company included an adjustment to amortize the excess deferred state taxes that it collected pursuant to the Commission's May 13, 2004 order in Docket No. M-100, Sub 138. The Company proposes that the excess deferred income taxes (EDIT) addressed in this order be returned to customers over a five-year period. The Public Staff believes that it would be more beneficial to return the EDIT to customers through a rider that will expire at the end of a two-year period. Peedin Exhibit 2 sets forth the Public Staff's calculations for the EDIT Rider.

ADDITIONAL COMMENTS

Q. DO YOU HAVE ADDITIONAL COMMENTS?

A. Yes. I have additional comments with regard to the lead-lag study submitted in the Company's filing in this case. As part of its filing in this case, DEP submitted a lead-lag study performed by Ernst & Young, LLP in 2011 using fiscal year 2010 data (the 2010 E&Y study). In conversations with Company personnel, DEP has informally advised the Public Staff that it did not commission a new lead-lag study for this case because the existing study was less than ten years old, and the Company believed it was still valid. The Public Staff reviewed documentation corresponding to samples of select 2016 test year transactions. The purpose of this sampling was to verify that the Company's 2016 test year lead-lag metrics were materially consistent with those determined in connection with the prior rate case in Docket No. E-2, Sub 1023. Based upon the Public Staff's investigation of the sample items, the Company submitted files containing revised and updated computations for certain schedules to correct the lead day times reported in error in its first submission. The Public Staff recalculated the "refreshed" lead day metrics and found that the Company's "refreshed" lead day times were materially understated for two of the schedules presented. The Public Staff inquired whether the Company believed that the "refreshed" metrics calculated by the Public Staff, or the Company's own "refreshed" metrics based on the 2010 E&Y study, were fairly representative of the entire population of 2016 test year transactions. The Company acknowledged, in general terms, that the Public Staff's analysis is a useful validation of the continuing applicability of the results of the 2010 E&Y study for this case. However, in acknowledgment of the lead day errors identified by the Public Staff, the Company stated that any adjustment to its lead-lag metrics would require a fully updated lead-lag study on all components of DEP's revenues and expenses.

The Public Staff believes that a fully updated lead lag study on all components should have been completed and recommends that the Commission direct the Company to prepare and file a lead-lag study in its next rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Darlene P. Peedin

I am a 1989 graduate of Campbell University with a Bachelor of Business Administration degree in Accounting. I am a Certified Public Accountant and a member of the North Carolina Association of Certified Public Accountants.

Since joining the Public Staff in September 1990, I have filed testimony or affidavits in several general and fuel clause rate cases of utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Virginia Electric and Power Company (Dominion Energy North Carolina), Nantahala Power & Light Company, Western Carolina University, and Shipyard Power and Light Company, as well as in several water and sewer general rate cases. I have also filed testimony or affidavits in other proceedings, including applications for certificates of public convenience and necessity for the construction of generating facilities and applications for the approval of cost recovery for Renewable Energy and Energy Efficiency Portfolio Standard (REPS) cases.

I was promoted to Accounting Manager with responsibility for electric matters in January 2017. I have had supervisory responsibility over the Electric Section of the Accounting Division since 2009.

Prior to joining the Public Staff, I was employed by the North Carolina Office of the State Auditor. My duties included the performance of financial, compliance, and operational audits of state agencies, community colleges, and Clerks of Court.

BY MS. DOWNEY:

Q. Okay. Ms. Peedin, did you prepare and cause to be filed, on November 22, 2017, supplemental testimony consisting of five pages and two exhibits with multiple schedules?

A. Yes.

Q. Do you have any changes or corrections to your supplemental testimony, other than the revised exhibits, which we will discuss in a minute?

A. No.

Q. Okay. Now, on November 28, 2017, corrected revised exhibits were filed; isn't that correct?

A. Yes, ma'am.

Q. Would you please explain what those corrections were to those exhibits?

A. Okay. So there were two corrections to the exhibits. The first was to update a reference for the update period from August to October. So on Schedule 1, where it says August, and throughout the exhibits where it says August, it will be October.

Q. Okay.

A. And the second --

Q. Go ahead.

A. -- would be to change a printing format. So if you were looking at my schedules, and you were looking at the upper left-hand corner where it says Peedin Exhibit 1, Schedule 1, and throughout the exhibits, changed the format so it would line up with the print range.

Q. Okay. Was that all on 11/28/17?

A. Yes.

Q. Okay. And the second revised exhibits filed on 12/4/17, what was the purpose of filing those second revised exhibits?

A. Okay. So the second revised exhibits were to add a line. So if you are looking at Peedin Exhibit 1, Second Revised, Schedule 1, we added line 36 in the unsettled issues section, which will take into account the litigation costs for the coal ash from outside services. So we have added a line item there. And as a result, it has changed several of my schedules. Schedule 1-1, we've added lines 8 and 9 to reflect the ongoing environmental costs and the outside services litigation costs related to coal ash. Schedule 3-1, which is a summary of all the adjustments, will change, specifically, page 2 of 4, column L, line 9. And, of course, the effects of the taxes, so all of that will change. And then Schedule 3-1, N, we added a column to reflect the unsettled amount for the coal ash litigation costs.

Q. Okay.

A. And let me just say one thing. The Peedin Exhibit 1 Second Revised Schedule 1 is exactly the same as the Settlement Exhibit 1, Second Revised Schedule 1, it's just the name in the top upper right-hand corner. So it's exactly the same.

Q. Thank you, Ms. Peedin.

MS. DOWNEY: Mr. Chairman, I move that the supplemental testimony of Darlene Peedin be copied into the record as if given orally from the stand and her exhibits be premarked as filed.

CHAIRMAN FINLEY: Ms. Peedin's supplemental testimony consisting of five pages is copied into the record as if given orally from the stand, and her Revised Exhibits 1 and 2 filed on November 27th as revised on November 28th, and second revised on December 4, 2017, are marked for identification as premarked in the filing.

(Whereupon, Second Revised Settlement Exhibit 1 and Second Revised Peedin Exhibit 1 were marked for identification.)

(Whereupon, the prefiled supplemental testimony of Darlene Peedin was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	SETTLEMENT TESTIMONY OF DARLENE P. PEEDIN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Settlement Testimony of Darlene P. Peedin

On Behalf of the Public Staff

North Carolina Utilities Commission

November 22, 2017

Q. MS. PEEDIN, WHAT IS THE PURPOSE OF YOUR SETTLEMENT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support the Agreement and Stipulation of Partial Settlement (Stipulation) between Duke Energy Progress, LLC (DEP or the Company) and the Public Staff (Stipulating Parties).

Q. PLEASE BRIEFLY DESCRIBE THE STIPULATION.

A. The Stipulation sets forth agreement between the Stipulating Parties in the following areas:

(1) Change in debt cost rate
(2) ROE and capital structure
(3) Update plant and accumulated depreciation
(4) Update revenues
(5) Distribution vegetation management

(6) Harris COLA

(7) Allocations by DEBS to DEP

(8) Adjustment for lost industrial revenues due to Hurricane Matthew

(9) EDIT levelized over 4 years

(10) Customer Connect expenses

(11) Aviation expenses

(12) Executive compensation

(13) Outside services (non-coal ash)

(14) Duke-Piedmont costs to achieve

(15) Depreciation expense

(16) Incentives

(17) Adjustment to coal inventory

(18) Sutton CT blackstart plant cost

(19) EOL nuclear M&S reserve expense

(20) Mayo ZLD

(21) Sponsorships and donations

(22) Lobbying expense

(23) Board of Directors expense

(24) Inflation adjustment

(25) Update of labor expenses through September 30, 2017

(26) Update Asheville CWIP balance to October 31, 2017

(27) Job Retention Rider (excluding pipeline companies & DEP shareholder contribution)

(28) PowerForward workshop

(29) SCP allocation methodology

(30) The Public Staff's recommendation that the Company prepare a Lead Lag Study in its next general rate case.

The details of the agreements in these areas are set forth in the body of the Stipulation.

Q. WHAT BENEFITS DOES THE STIPULATION PROVIDE FOR RATEPAYERS?

A. From the prospective of the Public Staff, the most important benefits provided by the Stipulation are as follows:

(a) A significant reduction in the $477,495,000 base non-fuel revenue increase requested in the Company's application, resulting from the adjustments agreed to by the Stipulating Parties.

(b) The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

Q. WOULD YOU BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE REVENUE REQUIREMENT ASPECTS OF THE STIPULATION?

A. Yes. The attached Peedin Revised Exhibits 1 and 2 set forth the accounting and ratemaking adjustments, and the resulting rate base, net operating income, return, and rate increase, to which DEP and the Public Staff have agreed. I note that not until the Commission makes a determination regarding the unresolved issues involving coal ash costs, storm costs, and the Job Retention Rider, can the accounting and ratemaking adjustments be finalized, and the resulting rate base, net operating income, return, and rate increase be calculated.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MS. DOWNEY:

Q. Mr. McLawhorn and Ms. Peedin, do you have summaries of your testimony?

A. (James McLawhorn) Yes.

Q. Let's start with you, Mr. McLawhorn.

A. The purpose of my testimony is fourfold: One, to support the agreement and stipulation of partial settlement entered into between the Public Staff and Duke Energy Progress and filed with this Commission on November 22, 2017; two, to give an overview of the Public Staff's investigation in this case, including our investigation of DEP's coal ash management practices; three, to introduce the other Public Staff witnesses; and four, to provide the Public Staff's recommendations on DEP's proposed job retention rider.

Based on the ratepayer benefits and other provisions of the stipulation, I recommend that it be approved as filed with the Commission. However, three areas of disagreement between DEP and the Public Staff remain for the Commission to resolve. One, recovery of coal ash costs; two, recovery of storm costs; and three, certain aspects of the proposed job retention rider. I will discuss the unresolved issues related to the JRR later in my testimony.

With respect to our investigation in this case, the Public Staff explored how technical, investment, accounting, and management decisions were made within DEP and tested whether those decisions were reasonable, prudent, and the lowest reasonable cost option consistent with the law, rules, regulations, and relevant case precedent. We approached each issue collectively and reached internal consensus for each position we have put forward in this case. Our internal task force was comprised of engineers, accountants, attorneys, and economists. In total, we utilized 27 internal personnel plus another 13 professionals in the consumer services division. The Public Staff also retained the services of five consultants to assist with the investigation of highly specialized topics in this case.

I will now introduce the Public Staff's other witnesses who are presenting testimony in support of this case.

First, Mr. Michael C. Maness, director of the Public Staff accounting division who presents accounting adjustments related to DEP's coal ash practices including the regulatory treatment of deferred coal ash costs, future coal ash costs, and allocation of coal ash costs. Mr. Maness also discusses adjustments related to the joint agency acquisition rider, storm costs, meter retirements, and depreciation.

Ms. Darlene Peedin, Public Staff accountant, who presents the accounting and ratemaking adjustment resulting from the Public Staff's investigation of the revenue, expenses, and rate base presented by DEP.

Mr. Jack Floyd, Public Staff engineer, presents testimony regarding cost of service, Customer Connect, AMI deployment, Power/Forward Carolinas, revenue assignment, and rate design.

Mr. Dustin Metz, Public Staff engineer, presents testimony regarding Public Staff adjustments related to coal inventory, material and supplies inventory at nuclear generation sites, and the newly constructed Sutton blackstart combustion turbine project.

Mr. Jay Lucas, Public Staff engineer, who presents testimony regarding Public Staff adjustments related to the Mayo zero liquid discharge system project and DEP's coal ash management practices, including coal ash sales, environmental violations, and

CCR and CAMA compliance activities.

Mr. Scott Saillor, Public Staff engineer, who presents testimony regarding operating revenues associated with customer growth.

Mr. Tommy Williamson, Public Staff engineer, who presents testimony regarding DEP's quality of service and Public Staff adjustments regarding storm-related costs and revenues and vegetation management.

Mr. Vance Moore and Mr. Bernie Garrett of Garrett and Moore, who present testimony regarding the prudence of DEP's coal ash management strategy decisions.

Mr. David Parcell, principal and senior economist of Technical Associates Incorporated, who presents his analysis of DEP's cost of capital and capital structure.

And finally, Ms. Roxie McCullar of William W. Dunkel & Associates, who presents her analysis of DEP's depreciation study filed in this case, including adjustments related to terminal net salvage.

Turning to the proposed job retention rider, the Company filed a petition on August 14, 2017, seeking approval of a job retention rider known as JRR-1 in Docket Number E-2, Sub 1153, which was later consolidated into this general rate case by the Commission on August 29, 2017. My review of DEP's filing was conducted in the context of the requirements and guidelines the Commission established in its order adopting guidelines for job retention tariffs, dated December 8, 2015, and, Docket Number E-100, Sub 73.

My review of the Company's application, proposed tariff, and draft application and agreement, as well as the Company's responses to the Public Staff's data request, indicates that the proposed rider JRR-1 generally complies with the JRT guidelines outlined in Appendix A to the Commission's JRT order.

I do have one area of concern regarding the proposed availability of the tariff to pipelines. The Commission has been clear that there must be a demonstrated need and way to verify the retention of jobs and load, which the Commission generally identified as industrial customers in its JRT order. A gas pipeline is a very different entity than an industrial manufacturing facility, because pipelines are fixed investments that cannot easily relocate to another area. Further, pipelines do not produce a finished product. In addition, there are many other types of entities not eligible for the proposed rider, JRR-1, that have a greater likelihood to relocate, go out of business, or reduce jobs and load than a gas pipeline. Thus, I recommend that the phrase, quote, transportation or preservation of a raw material of a finished product, end quote, be eliminated from the availability section of rider JRR-1.

I also disagree with DEP's proposal for a one-time shareholder revenue sharing of $3.5 million of the approximate $25 million annual revenue impact of rider JRR-1. Instead, I recommend that DEP shareholders should be responsible for the first $3.5 million on an annual basis. I believe my recommendation represents a fair sharing of revenue credit responsibility between DEP's customers and shareholders.

This concludes my summary.

Q. And Ms. Peedin, if you will read your summary.

A. (Darlene Peedin) Okay. The purpose of my testimony is to support the Agreement and Stipulation of Partial Settlement between Duke Energy Progress, LLC and the Public Staff. The stipulation sets forth all the areas of agreement and details of the agreement between the stipulating parties.

Peedin Revised Exhibits 1 and 2 set forth the accounting and ratemaking adjustments and the resulting rate base, net operating income, return, and rate increase to which DEP and the Public Staff have agreed. However, only when the Commission makes a determination regarding the unresolved issues involving coal ash costs, storm costs, and the job retention rider, can the accounting and ratemaking adjustments be finalized and the resulting rate base, net operating income, return, and rate increase be calculated.

The most important benefits provided by the stipulation from the perspective of the Public Staff are; one, a significant reduction in the base non-fuel revenue increase requested in the Company's application resulting from the adjustments agreed to by the stipulating parties; and two, the avoidance of protracted litigation between the stipulating parties before the Commission and possibly appellate courts. Based on these ratepayer benefits, as well as other provisions in the stipulation, the Public Staff believes the stipulation is in the public interest and should be approved.

This concludes my summary.

MS. DOWNEY: Mr. Chairman, the witnesses are available for cross.

CHAIRMAN FINLEY: All right. Cross examination?

MR. JENKINS: Thank you, Mr. Chairman.

CROSS EXAMINATION BY MR. JENKINS:

Q. Good afternoon, panel, my name is Alan Jenkins on behalf of The Commercial Group.

A. (James McLawhorn) Good afternoon.

A. (Darlene Peedin) Good afternoon.

Q. Mr. McLawhorn, these questions are directed to you and concern Staff's role in reviewing the proposed job retention rider. At page 17 of your testimony you took some issue with the availability definition of the type of customer that would qualify for the JRR.

What party drafted the definition?

A. (James McLawhorn) In the proposed tariff?

Q. Yes.

A. That would have been the Company.

Q. Was that specific definition required by the Commission's order on job retention guidelines?

A. Not the way I read the guidelines, no.

Q. Beyond the definition -- the availability definition that you discussed, did the Commission's job retention order prescribe the exact criteria that a utility should use to determine threshold eligibility for a customer qualifying for a job retention rider?

A. It did not prescribe specific standards, but it was pretty clear what needed to be included in a properly-designed job retention tariff -- what types of information.

Q. So it gave a general outline, and then the utility was supposed to come in with specifics of their particular proposal; is that right?

A. I would agree with that.

Q. Now, DE Progress proposed criteria whereby an applicant can qualify for the JRR by simply stating in its application that it has, at some time, considered acquiring ability to shift production elsewhere; isn't that true?

A. I think they have to follow verified statements. So to say that they just simply state it is probably not 100 percent accurate.

Q. Well, if you can look at the -- let's go to the application, itself, which -- the Company filed, at the back of its application, it's called "Application and Agreement For Job Retention Rider," and it's Application Exhibit Number 3.

A. Mr. Jenkins, I'm sorry, I don't have a copy of your original application with me.

MR. JENKINS: Can I approach?

CHAIRMAN FINLEY: Yes, sir.

BY MR. JENKINS:

Q. And my question is whether the -- there is a number of criteria that are listed there that the customer could verify, as you mentioned, but does not necessarily have to point out which of those criteria it is verifying; is that a fair statement?

A. Are you referring to the bullets under the heading that says, "To qualify for the job retention rider, the customer shall"; is that --

Q. Shall verify. There is four or five different ones. The last one says some other load issue.

A. Okay. I see where you are -- yeah. It says, "Certify one or more of the following conditions." So it doesn't -- it's not all-inclusive, no.

Q. And is it true, though, that one of those criteria could be satisfied by a customer verifying that, at some time, that customer considered acquiring

an ability to ship production elsewhere?
A. Yes.
Q. Okay. Will Staff verify whether an applicant can, in fact, ship production elsewhere?
A. Are you referring to our review of -- no, we can't verify that.
Q. Will DE Progress verify this statement?
A. No. Based on what they indicated to us in response to the data request, they will not.
Q. Do you think anyone could ever verify a statement whether an owner of a manufacturing facility has ever thought about acquiring an ability to ship production?
A. Unless the customer -- well, it would be very difficult to know what the -- beyond a shadow of a doubt. I agree with that.
Q. You agree there is a financial incentive for the applicant to verify that they might meet one of these criteria?
A. Well, to the extent that it will qualify them for the discount, yes.
Q. In its JRR application, the applicant can choose the level of employment that it agrees to maintain; is that right?

A. Yes. That would be set up front in the application process.

Q. And that level need not be the present employment level; is that right?

A. That's correct.

Q. It could be below the actual employment level; is that right?

A. It could be, yes.

Q. Now, will Staff verify whether the applicant has that employment level?

A. No.

Q. Will DE Progress?

A. My understanding is they will not.

Q. If the subsidy recipient does not, in fact, maintain the promised employment level, will the applicant be required to return the JRR subsidy it's received?

A. No, but they will be removed from the program on a -- of course, on a going-forward basis.

Q. Now, page 20 of your testimony, at line 2, you mention a concern that you have with respect to Staff's annual JRR report requirement, and can you summarize what your concern is?

A. Page 20, line 2?

Q. Line 20, I'm sorry.

A. Line 20, okay. Well, we just wanted to bring to the Commission's attention that the Commission has stated in the -- in its JRT guidelines that it expects the Public Staff to audit any programs, such as this, and report back to the Commission on customer compliance and on the effectiveness and the need of the program going forward, and we wanted to bring to the Commission's attention what we felt we would be able to do, as it is currently proposed, so there would be no misunderstanding when we filed a report with the Commission.

Q. Is it fair to say that part of your concern is -- and the thing you want to point out to the Commission is that Staff would have no independent ability to verify information?

A. That's correct. We will, basically, look at the customer's application that DEP will have on file and just be able to verify, yes, they submitted some information, and DEP has it in their files.

Q. Now, in that annual report, you mentioned that one of the things Staff is -- would be required to do is advise the Commission as to whether this JRR is effective?

A. That's the way I read the guidelines, yes.

Q. How does Staff intend to determine that the JRR is and has been effective?

A. Well, not having conducted an investigation yet, it's primarily going to be, as I stated in my testimony, that we are going to be able to say yes, there are customers who have signed up for the rider, they have filed the required information, and they are participating in the rider, and their employment level is X, and that's what we will know.

Q. Okay. In the annual -- in this annual report, will Staff be able to independently verify that any jobs have been saved that would not exist but for the rider?

A. No. And I think, as Mr. Wheeler testified last week, that it's very difficult to say that the mere presence of the rider, by itself, will save any jobs, but it will provide some benefit to customers who we know have been -- some industrial customers that we know have been having some difficult economic times in recent years, and so that, combined with other factors, would be a positive for them.

Q. Is it fair to say that this job retention rider is a hopeful exercise, that we hope it may achieve something, but we really can't verify it?

A. Well, there certainly are things we won't know 100 percent about it, but, I mean, it will positively impact the customer's bottom line. So we know it will have some positive impact.

Q. On the customers receiving the subsidies, right?

A. Yes. And we hope it has a positive benefit to all customers who are not left with stranded cost.

Q. Would you agree that the whole purpose of developing a criteria screen for JRR applicants is to provide some assurance to the Commission and ratepayers that JRR is narrowly tailored to address and meet the specific goal?

A. Yes, I would agree with that. And I would say -- I would point out that I went back and reviewed some of the criticisms that I made of the DEP proposal in their Sub 23 case five years ago, and I compared them to the proposed filing and to the changes that we agreed to in the stipulation, and there has been some very positive movement in this proposed rider versus the one in 2012.

Q. Do you recall that Mr. Wheeler testified that he expects nearly 100 percent of the 1,083 potential applicants for the JRR to qualify for the rider?

A. Yes, I heard him say that, and I would not be surprised by that at all.

Q. And that includes high-load factor, low-load factor, energy intensive, non-energy intensive, they all make it through this screen, right?

A. If they meet the requirements of having an aggregate demand of three megawatts or more, and the other requirements, then yes, I agree.

Q. And the other main requirement, and perhaps the only affect of the screen, is to screen out non-manufacturing customers, right?

A. No, I wouldn't agree with that. There are many customers that are classified as industrial customers that have demands less than three megawatts.

Q. Okay. That's a good point. Within the three -- within three sphere of customers with an aggregate load of three megawatts or more, the only real effective screen is the screen to screen out non-manufacturing customers, correct?

A. That's probably true, yes.

Q. Now, do you have -- do you not have any concern with DE Progress devising a screen for determining eligibility for its rider that lets through every applicant?

A. Well, we always are concerned about the potential for free riders on any rate or program, but I think we have to consider the purpose of the rider and the -- also, the difficulty of implementing more rigid screens. So you have to look at everything in context. And the Commission was clear, in my opinion, in its order in 2015 in the Sub -- E-100, Sub 73, the JRT guidelines, that the primary focus was to be on industrial customers.

Q. Given the situation that Staff, and really DE Progress, has no ability to verify information, the lack of any ability of the criteria to screen out applicants that might be free riders, why is Commissioner Brown-Bland's suggestion not appropriate, that a shorter-term or more narrowly tailored pilot program should be tried first?

A. Well, I'm -- that could certainly be a possibility. This is what was put in front of us. This is a pilot program. It's for five years. The Commission's guidelines said no more than five years, and it was designed to comply with those, and I believe it does comply with those. If the Commission feels that it should be shorter, that would be up to them.

Q. Lastly, I would like to look at how the proposed surcharge would be applied to customers. DE Progress proposed to build a JRR surcharge on a per kWh basis.

Is that particular billing method required by the Commission's job retention order?

A. I'd have to go back and check, but I don't believe it is required, but I say that subject to check.

Q. Okay. Are you aware that various residential and general service rate schedules of DE Progress provide that DE Progress bill customers for sales tax associated with the customer's underlying utility bill?

A. I believe that's correct, but subject to check.

Q. Now, since DE Progress obviously calculates and bills sales tax based on a percentage of the customer bill, do you have an opinion as to whether DE Progress could bill any job retention rider expense as a potential -- as a percentage surcharge on a customer bill?

A. I don't think I understand your question. Could you rephrase it?

Q. Yeah. There -- seems like there is two ways to bill a surcharge. One is on a per kWh basis, right?

A. Yes.

Q. And that would have varying impacts on customers, whether they are low-load factor or high-load factor, right?

A. Yes.

Q. And another way would be to just impose a surcharge, whatever the percentage is, 0.74 percent of a customer's total bill; that would be one way to do it, correct?

A. You mean just a straight percentage reduction?

Q. Yes.

A. Yes, that would be one way. That's somewhat analogous to what is done in their economic development rate schedules.

Q. Right. And so since DE Progress is able to do it on those schedules, and also is able to calculate sales tax based on the underlying bill, do you have an opinion as to whether DE Progress could bill this surcharge as a percentage bill?

A. Off the top of my head, I don't know any reason why they couldn't. That was not what was proposed, and we didn't evaluate that.

Q. Okay. Fair enough. Thank you.

CHAIRMAN FINLEY: Mr. Smith.

CROSS EXAMINATION BY MR. SMITH:

Q. Good afternoon. I just have a few questions on the JRR as well.

You just mentioned the application for the IER made by Duke Energy Progress five years ago in its last rate case; do you remember --

A. (James McLawhorn) Yes.

Q. -- discussing that briefly?

A. Yes.

Q. That wasn't approved, correct?

A. It was not approved in that case; that's correct.

Q. So industrial customers haven't been receiving that subsidy since that last rate case?

A. That is correct.

Q. And there hasn't been a mass exodus of industrial jobs from the state of North Carolina since then, has there?

A. Well, that's a pretty wide open -- I don't know what you mean by "mass exodus." I would agree that economic conditions have improved in the state since then. I also would say that we have also lost some industrial jobs and loads since then.

Q. Do you remember -- were you here for Mr. O'Donnell's testimony on behalf of CUCA?

A. Yes, I was.

Q. And he had testimony related to the loss of the entire LGS rate class?

A. Yes, I heard that. I believe he had similar testimony in the Sub 1023 case.

Q. I guess that's what I was referring to as a mass exodus, was a complete loss of the LGS load; that hasn't occurred, correct?

A. No, and I hope it does not.

Q. Do you have any reason to believe it would?

A. No. I don't believe we would lose the entire class, no.

Q. Do you agree that the U.S. Department of Defense is a large employer in the state of North Carolina?

A. Yes, I do agree with that.

Q. And if a large amount of load for the -- from a military base or another large customer that doesn't qualify for the JRR was lost, that would be stranded costs that would need to be covered by other customers as well, wouldn't it?

A. Yes.

Q. Have you done any analysis on the cost of the JRR to non-qualifying customers?

A. Well, I know the recovery of the revenue shortfall would have an impact on the entire customer base. It would be less than 1 percent. Somewhere in the .5 to .7 percent range.

Q. But --

A. That's overall. It could certainly have a different -- differing impacts on individual customers.

Q. Right. It would be more for large users, correct?

A. Yes. But I have not done any specific analysis on any specific customers.

Q. And some of those large users would be large employers as well, right?

A. I would assume so, yes.

Q. But there hasn't been any analysis done on whether or not the JRR will actually cost more jobs than it saves?

A. I have not done any such analysis, and I haven't seen any analysis done by anyone else.

MR. SMITH: All right. I have no further questions.

CHAIRMAN FINLEY: Other questions of the panel?

CROSS EXAMINATION BY MR. CULLEY:

Q. Mr. McLawhorn, I'm going to continue the trend and ask you a few questions about the job retention rider.

The Company has estimated a total cost of $24.8 million; is that correct?

A. (James McLawhorn) Yes.

Q. And the Company has proposed that shareholders will absorb $3.5 million of that amount, although the Public Staff would like to see the shareholders bear a larger share, correct?

A. Yes. We would like to see the $3.5 million extended -- that the shareholder contribution extended over the life of the pilot.

Q. So even extending that $3.5 million share over the five-year pilot program on an annual basis, ratepayers would still be responsible for covering some portion of the job retention rider costs, correct?

A. For the vast majority of the cost, yes.

Q. Great. So ratepayers who are not participating in the rider would be subsidizing the rates paid by the rider participants?

A. Yes. And I think that that's generally understood how the rider would work. That's not a surprise.

Q. Right. So you would agree that this is an instance of cross-subsidization?

A. Yes, but it -- there has been a marginal cost study, and we know that the other customers would be better off than they would be if a significant portion of the load were lost. So they should be better off, overall.

Q. So it's cross-subsidization with a rational basis, or a rationale, behind it?

A. Yes. I'm not sure we would support something like that if there weren't a rational basis.

Q. All right. Thank you, Mr. McLawhorn.

CROSS EXAMINATION BY MS. THOMPSON:

Q. Good afternoon. Mr. McLawhorn, I'm afraid my questions are for you, but I don't have too many.

A. (James McLawhorn) Okay. Ms. Peedin's getting lonely up here.

Q. I'm sorry, Ms. Peedin.

Mr. McLawhorn, are you familiar with the -- I'm sorry. I got off track.

Would you agree that it's sometimes

appropriate for the Company's -- for a utility company's shareholders to help to mitigate the impacts of a rate increase on certain customer sectors or classes, as a general principle?

A. Are you talking about the JRR or just in general?

Q. Just as a general principle.

A. Well, I mean, there have been instances in the past where shareholders have provided some initial contribution to a rate increase, and it did mitigate some of the initial rate impact.

Q. So you anticipated my next question, which is, there was a settlement between DEP and the Public Staff in DEP's last rate case, Docket Number E-2, Sub 1023; was there not?

A. Yes.

Q. And in that settlement, the Public Staff secured a commitment from DEP in which the Company agreed to contribute $20 million of a regulatory liability to a fund for low-income ratepayer assistance; does that sound right?

A. There was a provision, yes.

Q. And then $10 million of that $20 million was later directed to something called The Helping Home

Fund to pay for energy efficiency upgrades that allow low-income customers to reduce their electricity bills; are you familiar with that?

A. That sounds correct.

Q. The Company has not made any similar commitment in the settlement that it's agreed to with the Public Staff in this case, has it?

A. There is no commitment in this settlement.

Q. Just to the clarify for the record, there is no commitment to put shareholder dollars toward a fund to assist low-income customers with bill-payment assistance or efficiency upgrades, correct?

A. There is no commitment in the settlement -- the partial settlement between the Company and the Public Staff for shareholder funds; that's correct.

Q. Okay. Thank you. That's all I have.

CHAIRMAN FINLEY: Anyone else over here on the east side of the room? Mr. Page.

CROSS EXAMINATION BY MR. PAGE:

Q. I think I can just stand. Keep a seat.

Mr. McLawhorn, my questions are for you, just like everyone else.

Hey, Ms. Peedin, how are you? I hope you are having a great day.

A. (Darlene Peedin) I am.

Q. Subject to the resolution of the two caveats that you made about the JRT, one being the pipeline exception and the other being the source of funding after the first year; subject to those two caveats, does the Public Staff support the Commission approving the pilot program, JRT?

A. (James McLawhorn) Absolutely. I hope that was clear in my testimony.

Q. Thank you. That's all.

CHAIRMAN FINLEY: All right. Duke?

MR. SOMERS: Thank you, Mr. Chairman. Just a couple questions.

CROSS EXAMINATION BY MR. SOMERS:

Q. Mr. McLawhorn -- I'm sorry, Ms. Peedin, I'm gonna make you stay lonely, at least as far as my questions are concerned.

Related to the job retention rider, Mr. McLawhorn, you were asked some questions by Mr. Jenkins about, how in the world can the Public Staff or the Company verify what the applicants are stating, in terms of their eligibility for the job retention rider; do you remember that?

A. Yes.

Q. Are you familiar with North Carolina's law that allows industrial customers to opt out of the Company's or any utility's DSM/EE rates and programs?

A. Yes.

Q. And how is that verified?

A. By a letter from the company stating that they have performed some energy efficiency or have an energy audit done.

Q. When you refer to "the company," you mean the customer?

A. I mean the customer, yes.

Q. Is there anything different about the opt-out process for DSM/EE that was incorporated in the state law, in Senate Bill 3, in that verification process; is it materially any different than the process for the job retention rider?

A. In terms of how the customer asserts their situation, not significantly different.

Q. Thank you. I believe Mr. Smith asked you some questions about whether there has been a mass exodus of industrial jobs since the last rate case and disapproval of the IER; do you remember that question?

A. Yes.

Q. Did you review Mr. Wheeler's exhibits to his supplemental testimony that listed all the plant closings in the state of North Carolina?

A. Yes.

Q. If you were an employee who lost your job in a small town in Eastern North Carolina over that time period, would you consider that to be a mass exodus of industrial jobs?

A. Well, I would be concerned about the loss of my job, yes.

Q. Ms. Thompson also asked you some questions about Duke Energy Progress shareholder contributions to a low-income fund in the last rate case; do you remember that?

A. Yes.

Q. And in that case, the low-income funds were actually not shareholder dollars, but it was the early refund of certain costs of removal costs; do you recall that?

A. Yes.

MR. SOMERS: No further questions.

CHAIRMAN FINLEY: Redirect?

MS. DOWNEY: I don't have anything.

CHAIRMAN FINLEY: Questions by the Commission? Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Well, Ms. Peedin, I just have to ask you a question on general principle, and if you want to refer the question to someone else, you can do that.

So what analysis did the Public Staff undertake to determine that $3.5 million a year for five years was the correct level of shareholder contribution for the JRR?

A. (Darlene Peedin) I did not work on the JRR.

Q. Well, that's great. You can defer the question, but at least you got a question.

A. And I can defer that to Witness McLawhorn.

A. (James McLawhorn) Darn. Commissioner Clodfelter, we did not do any specific analysis. The Company offered that they would provide an initial $3.5 million contribution in year one, and that was -- we looked at that amount and said, well, they -- we didn't -- I don't know that there is really a way to do an analysis, but we felt that a healthy industrial base is certainly beneficial to the other ratepayers, otherwise we wouldn't support the rider, but it's also beneficial to the Company and its shareholders, so we thought a continuing contribution would be appropriate.

Q. They offered the number and you took it?

A. Right.

Q. That's all I wanted to know. Thank you.

EXAMINATION BY CHAIRMAN FINLEY:

Q. Ms. Peedin, I have a question or two for you.

A. (Darlene Peedin) Okay.

Q. If you would look at your Peedin Exhibit 1 Revised -- Second Revised Schedule 1.

A. Okay. Okay.

Q. And what I want to ask you about is the items on lines 33 -- strike that -- lines 34, 35, and 36. Those are the coal ash costs in dispute; are they not?

A. That is correct.

Q. And are there schedules behind this exhibit that break out the components of those costs?

A. For lines 34 and 35, I think Witness Maness has the breakout for those dollars; and for line 36, that would have been in my original testimony in my original exhibit for litigation costs related to outside services. And I think the amount on that schedule would have been, like, $88 million, and then if you apply the North Carolina retail allocation factor to that, you would get the $53,000.

Q. All right. Between your exhibit and

Mr. Maness' exhibits, is it possible to determine which of those costs have to do with closures of ash ponds? And what I mean by that: capping in place, or excavation, removal, and establishment of new repositories.

A. And I'm not sure about that, but Mr. Maness would be able to answer that question.

Q. All right. All right. Now, the Public Staff -- this is either one of you or both of you.

The Public Staff and the Company reached a settlement in this case pretty late in the game, right?

A. Yes, sir.

Q. We actually had to postpone the hearing because you were still negotiating; isn't that right?

A. Yes, sir.

Q. Now, because you settled on some of the -- and I saw people coming and going from the west side of the building, and red in the face, and so my assumption is that was not an easy process; is that correct?

A. That is correct.

Q. All right. Now, because you settled some of the issues that you -- you filed -- strike that.

You all filed testimony supporting your initial positions before you reached a settlement;

that's right, isn't it?
A. That is correct.
Q. Now, even though you settled some of the issues that you did, you don't concede, at this point in time, do you, that you were wrong in any of the positions that you took before you reached the settlement?
A. We are not conceding any adjustment that we made.
Q. All right.
A. And neither is Duke, I would have to say.
Q. And the seven of us sitting up here, we weren't privy to any of those discussions; we don't have any idea of what you fussed about and argued about, and why you settled this and didn't settle that, and how you reached that agreement; isn't that right?
A. That is correct.
Q. All right. Thank you. That's all I have.
CHAIRMAN FINLEY: Are there questions on the Commission's questions?
MS. DOWNEY: I have one --
CHAIRMAN FINLEY: Yes, ma'am.
MS. DOWNEY: -- if I may, Mr. Chairman.
EXAMINATION BY MS. DOWNEY:

Q. Mr. McLawhorn, Commissioner Clodfelter asked how you arrived at the -- where $3.5 million came from?

A. (James McLawhorn) Yes.

Q. Do you remember that question?

A. Yes.

Q. What authority would the Commission have to order $3.5 million over the five years?

A. Well, I don't know that the Commission can order the $3.5 million, but they can set the rider as to what level the rider can recover, and so they can set it at the approximately $25 million, less the $3.5 million, which would be $21.5 million, as it is for the first year. They could find that to be the reasonable amount for a recovery.

MS. DOWNEY: I don't have anything else.

CHAIRMAN FINLEY: All right. We will receive the exhibits of these witnesses, and you may be excused.

(Whereupon, Peedin Exhibit Numbers 1 and 2 were admitted into evidence.)

THE WITNESS: (James McLawhorn) Thank you.

MR. DODGE: Mr. Chairman, the Public Staff calls Bernard Garrett and Vance Moore.

VANCE MOORE and L. BERNARD GARRETT,
having first been duly sworn, were examined
and testified as follows:

DIRECT EXAMINATION BY MR. DODGE:

Q. Good afternoon, Mr. Garrett, Mr. Moore. I will start with Mr. Garrett.

Mr. Garrett, could you please state your name and address for the record?

A. (Bernard Garrett) My name is Bernie Garrett. My business address is 1100 Crescent Green Drive, Suite 208, Cary, North Carolina.

Q. By whom are you employed and in what capacity?

A. I'm the secretary treasurer of Garrett and Moore.

Q. Mr. Moore, could you please state your name and address for the record?

A. (Vance Moore) My name is Vance F. Moore. My business address is 1100 Crescent Green Drive, Suite 208, Cary, North Carolina.

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

A. I'm the president of Garrett and Moore.

Q. Did you cause to be jointly filed on

October 20, 2017, in this docket, confidential direct testimony consisting of 37 pages and 7 exhibits?

A. (Bernard Garrett) Yes.

Q. Do you have any additional changes or corrections to your October 20th testimony at this time?

A. (Vance Moore) Yes, we do.

Q. Could you please share those corrections?

A. On page 1, line 4, change "Suite 104" to "Suite 208." On page 1, line 4, change "Suite 104" to "Suite 208." On page 19, line 15, change "filed by the court-appointed monitor" to "submitted to NCDEQ." On page 21, line 4, change "DEQ" to "DEP."

Q. All right. Thank you. Did you also cause to be filed, on November 20, 2017, in this docket, confidential supplemental testimony consisting of nine pages and two exhibits?

A. Yes.

Q. And on December 4, 2017, did you file a corrected version of that confidential supplemental testimony to include line numbers?

A. Yes.

Q. Do you have any additional changes or corrections to your supplemental testimony at this time?

A. Yes, we do. On G&M Revised Exhibit 6, in the table under "tonnage summary CCR material on site as of January 1, 2015," for the 1982 basin, change 1,396,006 tons to 1,546,006 tons. On G&M Revised Exhibit 6, under "tonnage summary CCR material on site as of January 1, 2017," for the 1964 basin, change 2,940,000 tons to 2,903,505.

MR. BURNETT: Mr. Chairman, I'm sorry. Could I ask the witness to repeat that last one? I just missed where that last one was, just so I could note it down.

CHAIRMAN FINLEY: Yes, sir.

THE WITNESS: It's on Revised Exhibit 6, under "tonnage summary CCR material on site as of January 1, 2017," for the 1964 basin, change 2,940,000 to 2,903,505.

MR. BURNETT: Thank you.

BY MR. DODGE:

Q. All right. Thank you. So incorporating the changes and corrections we discussed, if I asked you the same questions today on the stand, would your answers be the same?

A. Yes.

MR. DODGE: Chairman Finley, at this time I move that the direct testimony and the supplemental testimony of Garrett and Moore, as corrected, be entered into the record as if given orally from the stand, and that their exhibits be marked as filed.

CHAIRMAN FINLEY: The direct testimony of Mr. Moore and Mr. Garrett consisting of 37 pages is copied into the record as if given orally from the stand, and their seven direct exhibits are marked for identification as premarked in the filing, and the nine pages of supplemental testimony, all that's corrected, is copied into the record as if given orally from the stand, and the two supplemental exhibits are marked for identification as premarked in the filing.

MR. DODGE: Thank you, Mr. Chairman.

(Whereupon, G&M-1 through 7, G&M Revised Exhibit 6, and G&M Supplemental Exhibit 8 marked for identification.)

(Whereupon, the prefiled direct and supplemental testimony of Vance Moore and Bernard Garrett was copied into the record as if given orally from the stand.)

PUBLIC

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of		
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF VANCE F. MOORE AND L. BERNARD GARRETT PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

PUBLIC

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Testimony of Vance F. Moore and L. Bernard Garrett

On Behalf of the Public Staff

North Carolina Utilities Commission

October 20, 2017

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

A. My name is Vance Moore. My business address is 1100 Crescent Green, Suite 104, Cary, North Carolina. I am the President of Garrett and Moore, Inc.

A. My name is Bernie Garrett. My business address is 1100 Crescent Green, Suite 104, Cary, North Carolina. I am the Secretary/Treasurer of Garrett and Moore, Inc.

Q. WHY ARE YOU PRESENTING JOINT TESTIMONY?

A. The Public Staff retained our firm, Garrett and Moore, Inc., to investigate the reasonableness of costs incurred by Duke Energy Progress, LLC ("DEP" or "Company"), with respect to its handling of Coal Combustion Residuals ("CCR" or "coal ash"). While we have

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received assistance from others, the two of us have conducted most of this investigation and have worked closely together. We have agreed upon the results and recommendations presented here. If we were to file separate testimonies, it would be largely redundant.

Q. BRIEFLY STATE YOUR QUALIFICATIONS.

A. We are registered professional engineers with many years of experience engineering coal ash management projects, including design and permitting of industrial landfills, closure of coal ash impoundments, and closure of coal ash landfills. Additional qualifications are set forth in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to present the results of our investigation into the prudence and reasonableness of costs incurred by DEP with respect to its coal ash management. In addition, we also present our perspective on the prudence and reasonableness of costs identified by DEP as part of its future regulatory obligations related to coal ash management.

Q. WHY DO YOU SAY "PRUDENCE AND REASONABLENESS"?

A. We are not experts in utility regulation, but have relied upon guidance from the Public Staff attorneys with respect to the legal standard for

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our investigation. Those attorneys inform us that under North Carolina General Statute 62-133, a utility's operating expenses must be "reasonable" to be included in the revenue requirement that is the basis for setting rates the utility may charge to consumers. Likewise, the cost of utility property allowed in the rate base, to which an authorized return may be applied, must also be "reasonable." Furthermore, we have been advised that management prudence is one aspect of this statutory reasonableness, and yet some costs or expenses can be prudent but still not reasonable for recovery as a component of the revenue requirement used for setting rates. For purposes of our testimony, we do not attempt to present the legal theory for a distinction between "prudence" and other "reasonableness"; rather, we just describe the facts that led us to conclude that a particular cost or expense is not reasonable for purposes of rate recovery.

Q. HOW DOES YOUR TESTIMONY DIFFER FROM THAT OF PUBLIC STAFF EMPLOYEES IN THIS CASE?

A. We understand that Public Staff witnesses Lucas and Maness speak to disallowance for costs of environmental violations, and the appropriate regulatory accounting treatment for coal ash-related costs. We do not address those issues.

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Q. WHAT IS THE SCOPE OF YOUR INVESTIGATION INTO THE PRUDENCE AND REASONABLENESS OF DEP'S COAL ASH MANAGEMENT COSTS?

A. We reviewed the approach taken by DEP to determine if it was the least cost method of achieving compliance the laws and regulations governing coal ash management. We conducted this review for each CCR unit – meaning each coal ash landfill, surface impoundment, structural fill, or other means of disposing of coal ash. To the extent that DEP had other reasonable compliance alternatives available, but selected a more costly alternative, it is our opinion that those costs were not prudently incurred and should be disallowed.

Q. PLEASE DESCRIBE THE RESOURCES UTILIZED IN CONDUCT OF YOUR INVESTIGATION.

A. In order to prepare this testimony, we reviewed the testimony and work papers of DEP witnesses Kerin, Wright, Bateman, and others. Through the Public Staff, we also submitted extensive discovery to DEP regarding its selection and analysis of CCR unit closure options, including the technical and financial basis for such decisions. We also participated in multiple meetings with Duke personnel and participated in site visits to the Sutton and Mayo facilities.

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Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Our testimony is divided into three parts. First, we provide a brief overview of DEP's legal and regulatory obligations related to coal ash management. Next, we review the costs incurred by DEP primarily related to coal ash management and the technical basis for the expenditures to indicate our opinion on the reasonableness of those decisions, and how those comport with providing the lowest cost compliance options for its customers.[1]

The third part of our testimony focuses on the technical basis for the future compliance alternatives proposed by DEP as part of its recognition of future legal and regulatory obligations. While DEP does not propose to utilize these future costs in this rate case for the determination of future rates, they form the basis for the regulatory accounting treatment proposed by DEP. As such, they require analysis as to the reasonableness of the technical basis for including these costs. The adjustments that we recommend in our testimony are incorporated into the rates proposed by Public Staff witness Maness.

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[1] The scope of our review was primarily focused on expenditures in the 2015 and 2016 timeframe and, with the exception of certain specific closure activities at Sutton undertaken by DEP, does not include costs in the update period of January 1, 2017, to August 31, 2017, although DEP's supplemental testimony filed on September 15, 2017, does include costs through that period. This limitation in our review was based on the volume of discovery and detail of analysis required to review those costs.

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CLOSURE OF COAL ASH IMPOUNDMENTS

Q. DO YOU AGREE WITH THE SUMMARY OF REQUIREMENTS REGARDING CCR AND CLOSURE OF COAL ASH IMPOUNDMENTS INCLUDED IN PAGES 23 THROUGH 36 OF DUKE WITNESS KERIN'S DIRECT TESTIMONY?

A. Yes, we have reviewed the discussion of regulatory requirements included in DEP witness Kerin's testimony and agree with his general characterization of the applicable federal and State regulations addressing the management and closure of CCR units in North Carolina and South Carolina.

Q. HOW DO YOU VIEW THE RANGE OF CLOSURE OPTIONS AVAILABLE TO DEP AS A RESULT OF THESE REGULATORY REQUIREMENTS?

A. To better understand the decision analysis the Company undertook in developing its closure obligations for each of the CCR units, we constructed a decision matrix based on the requirements that were established by the various statutory requirements in North Carolina, including S.L. 2014-122 ("CAMA 2014"), S.L. 2015-110 ("The Mountain Energy Act", or "MEA"), and S.L. 2016-95 ("CAMA 2016"). The decision matrixes are included as Exhibits 1 and 2 to our testimony.

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Q. ARE THERE OTHER FACTORS THAT HAVE POTENTIALLY IMPACTED DEP'S SELECTION OF CLOSURE OPTIONS?

A. Yes. As discussed by Public Staff witness Lucas and DEP witness Kerin, DEP entered into a consent agreement with the South Carolina Department of Health and Environment ("DHEC") applicable to ash management at the Robinson plant. In addition, the Settlement Agreement between the North Carolina Department of Environmental Quality ("NCDEQ"), DEP, and Duke Energy Carolinas, LLC ("DEC") required the accelerated remediation of ash basins and actions to address groundwater impacts at the Sutton, Belews Creek, Asheville, and H.F. Lee plants. Public Staff witness Lucas's testimony also addresses additional potential environmental violations that are still being investigated that may further impact the remediation of DEP's CCR units, and could therefore weigh into its selection of closure options. Our review, however, is based on actions taken by DEP to comply with applicable state and federal regulatory requirements, not on any settlements or litigation outcomes.

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Q. PLEASE PROVIDE A SUMMARY OF THE CLOSURE OPTIONS SELECTED AND CURRENTLY BEING IMPLEMENTED BY DEP FOR EACH OF ITS CCR UNITS.

A. Exhibit 3 provides a summary of the DEP CCR units, including the risk or priority ranking of each site, the estimated tons of CCR at each site, the timeframe for closure, a brief description of the current closure option selected by DEP, and the state or federal law that is applicable to the CCR unit creating the legal obligation at the site.

As discussed previously, the only DEP facility in South Carolina with CCR units is the Robinson Plant. Closure of the Robinson impoundments must comply with South Carolina and federal regulations, and the remediation plan must comply with the Consent Agreement entered into between DEP and DHEC. We do not take any exception with DEP's selected closure method for the CCR units at Robinson.

Of the seven DEP facilities in North Carolina, only two, Mayo and Roxboro, are governed by the risk classification assigned by NCDEQ. The classifications for the remaining facilities were deemed by the General Assembly as either Intermediate Risk (Cape Fear, H.F. Lee, and Weatherspoon) or High-Priority (Sutton and Asheville). With regard to Mayo and Roxboro, NCDEQ issued final

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classifications for these facilities as Intermediate Risk in May 2016. DEP is in the process of establishing the permanent replacement water supplies required under G.S. 130A-309.211(c)(1) and performing the applicable dam safety repair work at these sites. Upon completion of these tasks within the timeframe provided, NCDEQ must classify the impoundments at the sites as low-risk pursuant to G.S. 130A-309.213(d)(1).

Q. WHAT GUIDANCE DOES CAMA PROVIDE WITH REGARD TO CLOSURE OF THE CCR UNITS WHICH ARE CLASSIFIED AS "LOW RISK?"

A. Pursuant to CAMA 2014 low-risk impoundments must be closed as soon as practicable, but no later than December 31, 2029. At a minimum, the impoundment must be dewatered and closed either by excavation or by placement of a cap system that is designed to minimize infiltration and erosion. This approach is generally the most cost-effective means for closure of a CCR unit.

Q. DO YOU HAVE ANY CONCERNS WITH THE CLOSURE OPTIONS CURRENTLY IDENTIFIED BY DEP FOR MAYO AND ROXBORO?

A. It is important to note that CAMA2016 does not call for the submission of proposed closure plans for low- and intermediate risk impoundments until December 31, 2019. As such, DEP has not

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submitted a Site Analysis and Removal Plan ("SARP") to NCDEQ for any facilities other than Sutton and Asheville at this time. We take no exception to DEP's proposed closure method for the CCR units located at Mayo and Roxboro. We note, however, that citizen action lawsuits in federal court have challenged DEP's proposed closure methods for these sites.

Q. WHAT GUIDANCE DOES CAMA PROVIDE WITH REGARD TO CLOSURE OF THE CCR UNITS WHICH ARE DEEMED AS "INTERMEDIATE RISK?"

A. Section 3.(a) of CAMA 2016 provides that three DEP facilities, H.F. Lee, Cape Fear, and Weatherspoon steam stations, shall be deemed as Intermediate Risk and closed as soon as practicable, but no later than August 1, 2028. At a minimum, DEP must dewater and excavate the impoundments, at which time the CCR material can be either (i) disposed of in a coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill or (ii) used in a structural fill or other beneficial use as allowed by law.

Q. DO YOU AGREE WITH THE CLOSURE OPTIONS SELECTED BY DEP FOR CAPE FEAR AND H.F. LEE?

A. We take no exception to DEP's closure method for the CCR units located at Cape Fear and H.F. Lee. DEP has selected the Cape

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Fear Station and H.F. Lee Station as two of the three beneficiation sites pursuant to G.S. 130A-309.216. This provision, enacted as part of CAMA 2016, required Duke Energy to identify three sites located within the State with ash stored in the impoundments suitable for processing for cementitious purposes.[2] Upon selection of the sites, Duke was required to enter into a binding agreement for the installation and operation of ash beneficiation projects at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundments located at the sites.

We do note, however, that the timeframe proposed by DEP for beneficiation of these Intermediate Risk sites extends beyond the closure timeframe called for in Section 3.(a) of S.L. 2016-95 for deemed Intermediate Risk sites, and while G.S. 130A-309.215 provides a variance option for closure deadlines based on risk classifications made by NCDEQ, it does not apply to the closure dates applicable to the facilities that were deemed as Intermediate Risk.

[2] Duke also selected the Buck Steam Station facility, owned by Duke Energy Carolinas, LLC (DEC) as a beneficiation site pursuant to G.S. 130A-309.216.

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In addition, we note that DEP indicated in response to Public Staff data requests that while it has entered into agreements with SEFA (the processor) to engineer, fabricate and design the beneficiation units at Cape Fear and H.F. Lee, as well as the DEC Buck Facility, and has obtained the license and right to operate the beneficiation technology, it does not yet have executed agreements for processing or selling the processed ash from the Cape Fear and Buck facilities to concrete manufacturers. If DEP were to begin processing ash without a purchase agreement in place, DEP could incur additional costs associated with storage and management of the processed ash.

Q. DO YOU AGREE WITH THE CLOSURE OPTIONS SELECTED BY DEP FOR WEATHERSPOON?

A. We take no exception to DEP's closure method for the CCR units located at Weatherspoon. DEP has selected the excavation of CCR and beneficial use option, with contracts in place for the delivery of the CCR to facilities in South Carolina for use in the concrete industry, and this option appears to be at a lower cost than other closure options for the site. We further believe that DEP should have sought to establish Weatherspoon as one of the three beneficiation sites as required by G.S. 130A-309.216. DEP indicated in response to Public Staff data requests that

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> "Recycling ash to the South Carolina concrete industry at Weatherspoon does not qualify as one of the three beneficiation sites as required by G.S. 130A-309.216 is because we could only get a guaranteed commitment for 230k tons of product per year from the trucking company and cement companies. The volume requirement per G.S. 130A-309.216 is 300k of product per year."

DEP later indicated that it hopes to target an average of 245,000 tons per year to be taken by the cement companies, but that since there were not cement companies in North Carolina, they were required to solicit cement companies in surrounding states for beneficial reuse for cementitious purposes.

The least cost-effective site selected by DEC and DEP for the third beneficiation pursuant to G.S. 130A-309.216 is the DEC Buck station. The premium for selecting beneficiation at the Buck station, as opposed to lower cost closure options that comply with CAMA, would increase Buck's closure costs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. As such, we recommend that Duke continue to make commercially reasonable efforts to identify additional sites for cost-effective beneficial reuse of ash.

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Q. WHAT GUIDANCE DOES CAMA PROVIDE WITH REGARD TO CLOSURE OF THE CCR UNITS CATEGORIZED AS "HIGH-PRIORITY?"

A. SECTION 3.(c) of CAMA 2014 provides that the High-Priority sites shall closed as follows:

> (1) Impoundments located in whole above the seasonal high groundwater table shall be dewatered. Impoundments located in whole or in part beneath the seasonal high groundwater table shall be dewatered to the maximum extent practicable.
>
> (2) All coal combustion residuals shall be removed from the impoundments and transferred for (i) disposal in a coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill or (ii) use in a structural fill or other beneficial use as allowed by law. Any disposal or use of coal combustion products pursuant to this section shall comply with the moratoriums enacted under Section 4(a) and Section 5(a) of this act and any extensions thereof. The use of coal combustion products (i) as structural fill, as authorized by Section 4(b) of this act, shall be conducted in accordance with the requirements of Subpart 3 of Part 2I of Article 9 of the General Statutes, as enacted by Section 3(a) of this act, and (ii) for other beneficial uses shall be conducted in accordance with the requirements of Section .1700 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code (Requirements for Beneficial Use of Coal Combustion By-Products) and Section .1205 of Subchapter T of Chapter 2 of Title 15A of the North Carolina Administrative Code (Coal Combustion Products Management), as applicable.
>
> (3) If restoration of groundwater quality is degraded as a result of the impoundment, corrective action to restore groundwater quality shall be implemented by the owner or operator as provided in G.S. 130A-309.204.

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Q. WITH REGARD TO THE SUTTON FACILITY, PLEASE PROVIDE A SUMMARY OF THE CCR CLOSURE OPTIONS TAKEN TO DATE AT SUTTON.

A. In response to discovery from the Public Staff, DEP provided the following narrative discussion of the selection of closure options for the Sutton site.

> Excavation is the required coal ash basin closure plan for the two ash basins at Sutton, as dictated by the Sutton "high priority" site designation in the 2014 CAMA.
>
> Based on the CAMA August 1, 2019 required due date to close the two Sutton ash basins, it was necessary to promptly start excavating ash, and transporting it off-site while the potential for an on-site landfill could be investigated, otherwise the August 1, 2019 date would not be met. Ash excavation began, and transportation to the Brickhaven structural fill mine was initiated by truck, and then later transitioned to rail. The decision to build rail infrastructure on site is consistent with the principle of minimizing impact to neighbors, significantly increased the transportation efficiency, and considered the fact that Brickhaven was designed to accept rail delivery. At this time, the CCR landfill construction moratorium under CAMA 2014 remained in effect.
>
> Technical site characterization and investigation began for an on-site landfill, immediately to the east of the two ash basins. Landfill permitting was delayed approximately six months due to an environmental justice review, so transportation by rail continued. The 2016 CAMA Amendment under HB630 lifted the CCR landfill construction moratorium.
>
> The clay lined 1984 ash basin was also considered for whether it could be converted to a CCR landfill. Based on stability analysis, a low dam safety factor (for soil liquefaction) was identified for the 1984 ash basin. It did not meet the required calculated factor of dam safety for liquefaction required by the CCR Rule (1.13 actual versus required 1.20). Note that the 1971 ash basin does not have a clay liner, and does not meet three of

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> four dam safety factor requirements under the CCR Rule.
>
> The 1984 ash basin's immediate proximity to Lake Sutton, the embankment modifications necessary to address low factors of dam stability (from soil liquefaction), and the need to double handle the coal ash made the new adjacent CCR landfill the technically preferred option. In addition, unresolved questions regarding the requirements for clean closure by NCDEQ for ash basins in general (before the ash basin could be re-purposed), made the schedule for a CCR landfill in the 1984 ash basin location uncertain. Landfill construction adjacent to the existing ash basins gave better schedule assurance of meeting the August 1, 2019 due date for basin closure.
>
> Landfill construction is complete and excavated ash transfer to the on-site landfill is underway.

Q. DO YOU AGREE THAT THE MORATORIUM IN CAMA PROHIBITED THE CONSTRUCTION OF ALL ON-SITE LANDFILLS?

A. DEP's closure method appears to be based on the position that the moratorium in CAMA prohibited the development of an on-site industrial landfill through August 1, 2015. Therefore, DEP selected an off-site solution as the first phase of its Sutton closure. Section 5.(a)[3] established a moratorium on the construction of new or expansion of existing CCR landfills, defined by G.S. 130A-290(2c) as follows:

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[3] Section 5.(a) of S.L. 2014-122 established "a moratorium on construction of new or expansion of existing coal combustion residuals landfills, as defined by G.S. 130A-290(2c) and amended by Section 3(d) of this act." Pursuant to Section 5.(c), the moratorium expired on August 1, 2015. There were no further amendments to the expired CCR landfill moratorium in S.L. 2016-195.

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> "Coal combustion residuals landfill" means a facility or unit for the disposal of combustion products, where the landfill is located at the same facility with the coal-fired generating unit or units producing the combustion products, and where the landfill is located *wholly or partly on top of a facility that is, or was, being used for the disposal or storage of such combustion products,* including, but not limited to, landfills, wet and dry ash ponds, and structural fill facilities. *(emphasis added)*

This prohibited the construction of new or expanded CCR landfills that were located wholly or partly on top of a facility that is, or was, being used for the disposal or storage of such combustion products. It did not prohibit the establishment of a new industrial landfill outside of any basins, nor did it prohibit the establishment of a new landfill within a basin that had been cleaned up and no CCR materials would remain below the landfill. As Section 5.(a), stated, "the purpose of this moratorium is to allow the State to assess the risks to public health, safety, and welfare; the environment; and natural resources of coal combustion residuals impoundments located beneath coal combustion residuals landfills to determine the advisability of continued operation of these landfills."

Q. DID DEP REVIEW COST ESTIMATES COMPARING AN ON-SITE LANDFILL AND AN OFF-SITE STRUCTURAL FILL PROJECT?

Yes. DEP retained Geosyntec to review conceptual closure options and provide preliminary cost estimates for multiple sites, including the Sutton Plant in 2014. Exhibit 4 includes an excerpt from the

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September 2014 Closure Options Feasibility Analysis Report for the Sutton Plant prepared by Geosyntec Consultants, including the executive summary, Table 4.T1 containing preliminary closure cost estimates, and the conceptual drawing of on-site greenfield landfill from Appendix 3.A7. This report indicated that both on-site greenfield landfills and on-site landfills within the excavated 1984 ash basin footprint were technically feasible and significantly less expensive than any of the off-site disposal options.

Q. DID DEP ULTIMATELY APPLY FOR AND RECEIVE A PERMIT TO CONSTRUCT AND OPERATE AN INDUSTRIAL LANDFILL AT THE SUTTON SITE?

A. Yes, DEP submitted its Site Application and On-site CCR Landfill Construction Application to NCDEQ in May 2015 and August 2015, respectively. The schedule originally assumed that DEP would receive a landfill construction permit by June 2016. We consider this a reasonable assumption. In April 2016, NCDEQ initiated an environmental justice review for the landfill construction permit and, upon completion, transmitted it to the United States Environmental Protection Agency ("EPA") for review and comment; EPA did not act on the environmental justice review. The permit was ultimately issued by NCDEQ on September 21, 2016. We do not consider this delay to be relevant to the decision made in 2014 to pursue an

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off-site structural fill as part of its first phase of environmental cleanup. Duke called this development "unexpected" in its July 28, 2017, Semi-Annual Report on Closure and Excavation - Asheville, Dan River, Riverbend, And Sutton ("July 2017 Semi-Annual Report") submitted to the Court-Appointed Monitor as a result of its plea agreements in the criminal actions brought by the U.S. Department of Justice following the 2014 Dan River coal ash spill.[4]

Q. DID THE DELAY IN THE PERMIT ISSUANCE IMPACT DEP'S EXECUTION OF THE CLOSURE PLAN FOR THE SUTTON FACILITY?

A. DEP indicated in response to discovery that as a result of the delay in receiving its permit, DEP will be forced to operate with little to no margin to achieve the August 1, 2019, CCR surface impoundment closure date. The Site Analysis Removal Plan filed by the Court-Appointed Monitor on April 13, 2017, indicates that closure will be completed in February 2020, and this closure date is further forecasted by Duke in its July 2017 Semi-Annual Report.

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[4] *U.S. v. Duke Energy Bus. Servs., LLC, et al.,* Case Nos. 5:15-CR-00062, 5:15-CR-00067, 5:15-CR- 00068 (E.D. N.C., May 14, 2015).

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Q. WERE THERE ANY OTHER DELAYS IN THE EXECUTION OF DEP'S CLOSURE PLAN?

Yes. The Permit to Operate for the Brickhaven structural fill facility was received from NCDEQ on October 15, 2015. The first full month of rail hauling did not occur until March of 2016.

Q. DID THE BRICKHAVEN STRUCTURAL FILL FACILITY PROVIDE ANY ADVANTAGE REGARDING THE ASH PROCESSING RATES?

No. The average ash processing rate (ash being hauled off-site by rail) was approximately 110,000 tons per month. DEP indicated in its July 2017 Semi-Annual Report that the on-site landfill will be able to receive 200,000 tons per month.

Q. DO YOU BELIEVE THAT THE TIMEFRAME FOR PERMITTING AN ON-SITE INDUSTRIAL LANDFILL REQUIRES MORE TIME OR INVOLVES MORE RISK THAN THE PERMITTING OF AN OFF-SITE STRUCTURAL FILL SITE?

A. No. We evaluated the proposed timeframe for seeking an on-site industrial landfill as opposed to the permitting process for an off-site structural fill site, and believe that neither timeframe presented a significant advantage over the other. Assuming a start date of June 2014, (the timeframe during which DEP was evaluating off-site

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options for disposal of ash from Sutton), a Site Plan Application and Construction Plan Application would take no more than six months to prepare and submit to NCDEQ. Using the same assumption made by DEQ, the NCDEQ review time would be about nine or 10 months. Following issuance of the permit, approximately 10 months would be needed to construct the initial landfill phase and receive a permit to operate for the on-site landfill project. Therefore, it would have been reasonable to assume that an on-site landfill would be ready for ash disposal around July of 2016. Using DEP's stated production rate of 200,000 tons per month for the on-site landfill; the 5.4 million tons of ash could be excavated and disposed in the landfill in about 27 months, with a completion date for ash excavation would be around October 2018. This would also provide a reasonable contingency of approximately nine months to the August 2019 closure deadline. Further, it is important to note that the landfill construction schedule would not have impacted the overall schedule. The current landfill contractor's schedule indicated that Cells 3-8, which provide about five million tons of capacity, will be constructed in 24 months.

In addition to much lower costs, we also note that the on-site disposal presented reduced risk compared to off-site disposal, reduced transportation costs, and to some extent less controversy than the

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selected Brickhaven structural fill facility.[5] As such, we believe that had DEP expeditiously pursued an on-site industrial landfill at the time it began working on the structural fill facility, it could have disposed of all of the ash on-site without incurring the added expense associated with the off-site transfer and disposal.

Q. WHAT IS YOUR POSITION WITH REGARD TO WHETHER DEP'S CUSTOMERS SHOULD BE REQUIRED TO PAY FOR THE ADDITIONAL COSTS ASSOCIATED WITH THE OFF-SITE DISPOSAL ORIGINALLY PURSUED BY DEP FOR THE SUTTON FACILITY?

A. We do not believe the costs expended to haul the coal ash off-site to the Brickhaven structural fill facility were reasonable or prudent, when compared with lower cost, on-site disposal options. Therefore, we recommend that the Commission disallow the difference in costs from DEP's request in this proceeding. This is discussed below in our recommended adjustments to DEP's request.

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[5] The Public Staff notes that the Brickhaven facility was the subject of litigation by Chatham County that ultimately included the payment of additional tipping fees and other consideration as part of the settlement. In addition, the Public Staff notes that the **[BEGIN CONFIDENTIAL]** contract with Brickhaven includes at-risk provisions to the utility in the event of early termination following the securing of all necessary permits by Charah **[END CONFIDENTIAL]**.

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Q. DO YOU HAVE ANY OTHER CONCERNS AT THIS TIME REGARDING THE CLEANUP COSTS INCURRED BY DEP FOR THE SUTTON FACILITY?

A. Yes. In preparing the cost adjustments for the Sutton facility, one component of the adjustment was to add cost to the paid to date amounts for the on-site landfill construction on an accelerated schedule, as further discussed below. In calculating these additive costs, we did not include two specific liner components, called "Secondary Geocomposite Layer" and "Secondary 60-mil HDPE Textured Geomembrane Material." These two liner components were included in DEP's current on-site landfill construction contract. Federal and state regulations do not require a "Secondary Geocomposite Layer" and "Secondary 60-mil HDPE Textured Geomembrane Material." Therefore, the cost of these components were not included for the on-site landfill construction on an accelerated schedule. Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was not included in the amount for the on-site landfill construction on an accelerated schedule to account for this exception.

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Q. WITH REGARD TO THE ASHEVILLE FACILITY, PLEASE PROVIDE A SUMMARY OF THE CCR CLOSURE OPTIONS TAKEN TO DATE AT ASHEVILLE.

A. The two CCR units at the Asheville Plant include: (i) the 1982 Ash Basin; and (ii) the 1964 Ash Basin. DEP had been excavating ash from the 1982 Ash Basin since 2007 in order to provide structural fill material for the Asheville Regional Airport, hauling this material by truck. Duke indicated that following passage of CAMA 2014, which deemed Asheville a High-Priority site that was subject to an August 2019 closure date, it was necessary to continue excavating ash, and transporting it off-site while the potential for an on-site landfill could be investigated. Passage of the Mountain Energy Act of 2015 later amended the required completion date for closing the two ash basins at Asheville to August 1, 2022, to allow time for the construction of a combined cycle plant on the site, and retirement of the existing coal-fired generating station.

Upon completion of the airport structural fill project, DEP began re-directing the excavated ash to the solid waste landfill operated by Waste Management at Homer, Georgia for ultimate disposal. Some smaller amounts were also hauled to the Cliffside on-site landfill for disposal. Excavation of the 1982 Ash Basin was completed in

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September 2016, at which time the Basin was turned over for dam decommissioning and construction of the combined cycle plant.

Duke indicated that it had previously considered the 1964 Ash Basin as a possible location for an on-site landfill, but indicated that seismic issues and its proximity to the French Broad River prevented this option. In addition, given that the excavated 1982 Ash Basin was being re-purposed for the combined cycle plant construction on an aggressive schedule, it was no longer available for temporary storage of ash from the 1964 Basin, which would make compliance with the August 1, 2022 closure date for the 1964 Ash Basin unachievable. DEP has continued to excavate ash from this site, with the ash being transported off-site by truck to Homer, Georgia.

Q. HAS DEP PROVIDED CONSISTENT INFORMATION REGARDING THE AMOUNT OF ASH BEING EXCAVATED FROM THE ASHEVILLE FACILITY?

A. No. The amount of ash that has been excavated and moved off-site, as well as the ash remaining on the site, is presented very differently by DEP in various filings. Exhibit 5 provides a summary of various ash quantities reported by DEP at the Asheville facility for the 2015-2016 timeframe. This range of numbers represents the "moving target" that DEP has established with regard to its ash management

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at the site and raises questions about whether the ash processing costs at Asheville have been imprudently incurred.

Q. DO YOU AGREE WITH THE CLOSURE APPROACH UTILIZED BY DEP FOR THE ASHEVILLE FACILITY?

A. We agree with use of CCR at the Asheville Airport as a structural fill project, and the need for expeditious handling of the ash to allow development of the proposed combined plant at the Asheville site pursuant to the Mountain Energy Act, but believe that some of DEP's ash processing costs at the site since that time have been unreasonable. In addition, on an ongoing basis, we believe DEP should further evaluate other lower cost remediation options for the remaining ash on the site.

Q. MORE SPECIFICALLY, CAN YOU DESCRIBE THE ASH PROCESSING ACTIVITIES TAKEN BY DEP THAT HAVE BEEN UNREASONABLE?

A. DEP spent approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** under the category of ash processing in 2015 and 2016, with the costs generally broken down as follows: **[BEGIN CONFIDENTIAL]** [redacted]

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[redacted]

[redacted] **[END CONFIDENTIAL]**. As indicated in Confidential Exhibit 6, the remaining amount was spent to achieve a net reduction of 113,000 tons of ash on the site.

While it is difficult to calculate an exact adjustment to the amounts spent, it is reasonable to conclude that the execution of the project was not cost effective. Utilizing the current unit price in DEP's current contract with Waste Management for off-site disposal to the R&B Landfill at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which includes steps from excavation to disposal

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at the facility, this amount of ash could have been disposed of at a much lower cost to customers, as shown in Exhibit 6.

Q. **WHAT FURTHER ACTIONS DO YOU BELIEVE DEP SHOULD CONSIDER TO ACHIEVE A TIMELY CLOSURE OF THE ASHEVILLE FACILITY IN A MORE COST-EFFECTIVE MANNER FOR RATEPAYERS?**

A. Upon passage of the MEA in 2015 which extended the closure deadline for the CCR units at the Asheville facility to December 31, 2022, DEP should have pursued an on-site industrial landfill. It does not appear DEP evaluated or identified fatal flaws eliminating the possibility of an on-site industrial landfill. Had an on-site industrial landfill capable of storing three million tons of CCR been pursued, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in hauling costs could potentially be avoided. While the design and construction of an on-site industrial landfill at the Asheville facility would have been technically challenging, it is our opinion that it could be done at a lower cost than hauling the remaining CCR off-site.

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Q. PLEASE SPECIFY THE COSTS RELATED TO CLOSURE OF CCR UNITS FOR WHICH YOU BELIEVE THAT DEP DID NOT PROVIDE SUFFICIENT SUPPORT FOR INCLUSION IN THIS RATE PROCEEDING?

A. As discussed previously, it is our opinion had DEP pursued the on-site industrial landfill at Sutton as early and diligently as the development of the off-site Brickhaven structural fill facility, the on-site industrial landfill would have been completed and ready to accept CCR materials on a similar schedule as the off-site Brickhaven structural fill facility. Therefore, cost for transportation of excavated CCR, initially by truck, and then later by rail, could have been avoided. The cost avoided by utilizing an on-site industrial landfill verses transportation of excavated CCR, initially by truck, and then later by rail, to the off-site Brickhaven structural fill facility are shown in Confidential Exhibit 7.

With regard to the ash processing costs at Asheville, we also recommend that DEP's cost recovery should be limited to DEP's off-site disposal rates, as opposed to the costs actually incurred for the removal of 467,000 tons. The difference in actual costs versus the costs of the off-site disposal rate, as shown in Confidential Exhibit 6, should be disallowed.

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FUTURE ARO COST CONCERNS

Q. DID YOU EVALUATE THE ADDITIONAL COST INPUTS USED BY DEP TO DETERMINE ITS FUTURE REGULATORY OBLIGATIONS?

A. Yes, DEP provided forecasted costs for the period 2017 through 2057. The forecasts are created by initially estimating costs associated with each line item, with the exception of inflation escalation, and summarized to establish a total cost in 2016 dollars. The cost forecast for each year is then estimated by establishing how much of each line item will be expended for each year in the forecast period and then summarizing all line items annually. Since all costs are in 2016 dollars, an inflation escalation is applied to the costs utilizing a compounding formula to determine the inflation impacts in today's dollars.

Q. DO YOU AGREE WITH THE ALL OF THE INPUTS UTILIZED TO ESTABLISH THESE FORECASTED COSTS?

A. DEP has only submitted a Site Analysis and Removal Plan ("SARP") for its High-Priority sites at this time, so it is difficult to provide a meaningful evaluation of the forecasted costs for coal ash remediation at those facilities. Therefore, it is critical that these costs be closely reviewed as they are expended and prior to inclusion in rates or any other future cost recovery mechanism. However, there

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are several categories of forecasted costs that we believe are unreasonable and excessive, including the following:

First, DEP indicated that it may be subject to an "Unfullfillment Fee" for its three deemed Intermediate Risk facilities in the following amounts: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

The Unfulfillment Fee is based on the contractual obligation DEBS (acting as agent for DEP and DEP) entered into with Charah, Inc., on November 12, 2014, for the placement of CCR at the Brickhaven Structural fill facility in Chatham County and the Colon Structural fill facility in Lee County. The contract called for the facilities to being designed to accept 20,000,000 tons of capacity at a total development cost **[BEGIN CONFIDENTIAL]** [redacted]

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[redacted] **[END CONFIDENTIAL]**.

The Unfullfillment Fee therefore appears to represent the Prorated Costs associated with termination of the purchase orders for the placement of ash from the three facilities at the Brickhaven or Colon structural fill facility. It is our understanding, however, that the final status of the mine reclamation permits necessary for the Colon Structural fill facility is still uncertain. As a result, it is not clear whether a "Prorated Cost Triggering Event" has occurred under the contract. If, however, a Prorated Cost Triggering Event is viewed to have taken place, then the purchase orders for the placement of ash

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at the Brickhaven or Colon facilities from the Cape Fear, H.F. Lee, and Weatherspoon facilities that were terminated as a result of Duke's decision to utilize beneficiation at these sites would potentially subject DEP to payment of Prorated Costs. It appears that Duke has taken the worst-case scenario with regard to total fees at the facility, assuming the full development costs will be incurred. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. As such, these costs, if ultimately incurred by Duke, appear excessive.

In addition, we believe that some of the cost estimates for bulk water and interstitial water treatment appear to be overstated. DEP generally relied on two quotes for these cost estimates, the first being based on the contract for the water treatment system being utilized at the Sutton facility, which is used generally for all facilities. While the Sutton system is operational and provides real costs on which to base the estimate, the Sutton facility has unique water management and treatment characteristics that required a more advanced and higher cost water treatment system. The second

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estimate for water treatment is based on the costs for the facility at Riverbend, which was applied to the facilities that were being beneficiated pursuant to G.S. 130A-309.216. It is our opinion that the characteristics of water treatment at each facility are sufficiently different to justify evaluation of the most cost-effective water treatment options on a plant-by-plant basis. As a point of reference, dewatering and bulk water treatment costs generally make up approximately 10-15% of the total remediation costs at a facility.

CONCLUSIONS

Q. PLEASE PROVIDE A SUMMARY OF THE ADJUSTMENTS TO DEP'S REQUEST FOR COST RECOVERY THAT YOU RECOMMEND.

A. Our adjustments contained in Exhibits 6 and 7 reflect adjustments to the costs incurred at DEP's High-Priority sites, Sutton and Asheville, which make up the vast majority of coal ash management costs incurred by DEP to date. These adjustments are included in the testimony of Public Staff witness Maness in his recommendations for the appropriate recovery of these costs. As previously noted, the scope of our review was primarily focused on expenditures in the 2015 and 2016 timeframe and, with the exception off the Sutton adjustment, does not include costs in the update period of January 1, 2017, to August 31, 2017, although DEP's supplemental testimony

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filed on September 15, 2017, does include costs through that period. The volume of discovery and detail of analysis required in review of coal ash management costs was too great for us to conduct additional review after September 15 for another eight months of invoices and cost categories. There undoubtedly should be additional adjustments for the January – August 2017 period beyond those we recommend; however, because our analysis depended on the review of individual expenditures we do not attempt the short-cut approach of recommending a 2017 disallowance based on the same ratio of disallowance to costs that we have for 2015 and 2016. While we did not have the capabilities to calculate a recommended adjustment for 2017 coal ash management costs in the time available after DEP's update, we do believe this further supports the equitable sharing concept for coal ash costs as recommended by Public Staff witness Maness.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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Appendix A

Qualifications of Garrett and Moore, Inc.

Garrett and Moore, Inc., specializes in engineering services for power and waste industries. We remain focused and specialized in these markets and are dedicated to continuing to advance the reputation of excellence our staff has established through the years. Our company has been responsible for the construction administration and Construction Quality Assurance for about $90 million worth of lined landfill, final cover system, and lined wastewater pond construction since 2007, with much of that work specific to CCR landfills and ash basins. We have familiarity with the federal CCR Rule and the North Carolina Coal Ash Management Act, and have tremendous experience with CCR disposal methods and their associated costs.

Vance Moore and Bernie Garrett have specialized expertise in the following areas:

Coal Combustion Residuals

Through our firm of Garrett and Moore, Inc., we have provided engineering and consulting services to support power companies in the management of coal combustion residuals (CCRs), including but not limited to the following:

- ☐ Groundwater Monitoring
- ☐ Groundwater Corrective Action
- ☐ Hydrogeological Investigations
- ☐ Site Characterization Studies
- ☐ Geotechnical Evaluations
- ☐ Stability and Liquefaction Analysis
- ☐ Ash Pond Closure Design
- ☐ FIN 47 Cost Liability Estimating
- ☐ Ash Pond Closure Construction
- ☐ Ash Pond to Landfill Conversion
- ☐ Source Remediation
- ☐ Dewatering Design
- ☐ Ash Landfill Siting & Design
- ☐ Ash Landfill Construction
- ☐ Landfill Closure & Post-Closure
- ☐ Federal CCR & CAMA Rule Guidance
- ☐ Regulatory Compliance
- ☐ Environmental / Permit Audits

Solid Waste Engineering

Through our firm of Garrett and Moore, Inc., we have provided full-service solid waste design and permitting services for municipal solid waste (MSW), construction and demolition debris (C&D), land clearing and inert debris (LCID), industrial waste, tire monofills, and coal combustion ash landfills. We have a very successful track record of overseeing landfill development projects from concept to operations. Our expertise in solid waste engineering includes the following:

- ☐ Facility Siting Studies
- ☐ Engineering Design
- ☐ USEPA HELP Modeling
- ☐ Slope Stability & Liquefaction Analysis

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- ☐ Settlement and Bearing Capacity
- ☐ Alternative Liner Analysis
- ☐ Stormwater Management & Design
- ☐ Equivalency Determinations
- ☐ Recyclables Program Management
- ☐ Landfill Closure & Post-Closure
- ☐ Convenience Center Planning / Design
- ☐ Waste Treatment & Processing
- ☐ Landfill Gas Remediation Plans
- ☐ Leachate Management System Design
- ☐ Landfill Gas Planning and Design
- ☐ Operations Planning
- ☐ Life of Site Analysis
- ☐ Alternate Final Cover Evaluations
- ☐ Transfer Stations
- ☐ Compost Systems
- ☐ Special Waste Permitting
- ☐ Operations & Maintenance

Bernie Garrett and Vance Moore have been providing engineering services for CCR management projects continuously since 1995. Over the last 10 years, we have performed all engineering associated with CCR management projects at all six of SCE&G's coal fired power plants, as well as facilities owned and operated by Santee Cooper. Our credentials include the following:

■ **Vance F. Moore, P.E**

Mr. Moore is a principal and founding member of Garrett and Moore.
Mr. Moore has 27 years of experience providing environmental engineering and consulting services to the power and waste industries. He has provided design, permitting, construction quality assurance, and operations support for numerous RCRA Subtitle D landfill projects, ash landfill projects, ash landfill closure projects, and ash pond closures in North and South Carolina.
Registrations: Professional Engineer – Georgia, North Carolina, South Carolina
Education: B.S., Civil Engineering, North Carolina State University, 1989
Associations: North Carolina SWANA Chapter - Technical Committee.
South Carolina SWANA Chapter

■ **Bernie Garrett, P.E.**

Mr. Garrett is a principal and founding member of Garrett and Moore.
Mr. Garett 27 years of experience providing environmental engineering and consulting services to the power and waste industries. His experience and professional responsibilities have progressed from project engineer with a major national engineering firm, project manager on solid waste landfill projects with a regional engineering firm, to client/project manager responsible for comprehensive engineering and consulting at Garrett and Moore, Inc.
Mr. Garrett has been working on coal ash management projects continuously since 1999. He has provided design, permitting, and construction quality assurance and operations support for ash pond closures, ash landfill projects, and ash landfill closure projects.
Registrations: Professional Engineer in Georgia, North Carolina, South Carolina, and Virginia.
Education: B.S. Civil Engineering, Virginia Tech (1989);
M.S. Environmental Engineering, Old Dominion University (1996)
Associations: PENC Central Carolina Chapter Board of Directors
ACEC/PENC Solid and Hazardous Waste Subcommittee

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	SUPPLEMENTAL TESTIMONY OF VANCE F. MOORE AND L. BERNARD GARRETT PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Supplemental Testimony of Vance F. Moore and L. Bernard Garrett

On Behalf of the Public Staff

North Carolina Utilities Commission

November 20, 2017

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

A. My name is Vance Moore. My business address is 1100 Crescent Green, Suite 208, Cary, North Carolina. I am the President of Garrett and Moore, Inc. I am the same Vance Moore who previously filed direct testimony on behalf of the Public Staff in this docket on October 20, 2017.

A. My name is Bernie Garrett. My business address is 1100 Crescent Green, Suite 208, Cary, North Carolina. I am the Secretary/Treasurer of Garrett and Moore, Inc. I am the same Bernie Garrett who previously filed direct testimony on behalf of the Public Staff in this docket on October 20, 2017.

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Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of our supplemental testimony is to make one correction in our direct testimony related to the Sutton on-site landfill, and one change to our testimony regarding the quantity of coal combustion residuals (CCR) excavated from the 1982 basin at the Asheville plant based on supplemental information provided by Duke Energy Progress, LLC (DEP). This information, provided after the filing of our testimony in response to earlier Public Staff data requests, along with the rebuttal testimony of DEP witness John Kerin, modified our understanding of the amount of CCR in our testimony. We are also making changes to G&M Exhibit No. 6 that was filed as part of our original testimony on October 20, 2017, and including a new G&M Supplemental Exhibit No. 8.

Q. PLEASE DESCRIBE THE CORRECTION YOU ARE MAKING TO YOUR TESTIMONY RELATED TO THE SUTTON ON-SITE LANDFILL.

A. In our direct testimony, we incorrectly used the quantity of CCR located at the Sutton facility as of January 1, 2017, in our calculation of the timeframe for disposal of waste in the on-site greenfield landfill. Instead, we should have used 6,320,000 tons, which was the estimated combined quantity of CCR utilized by DEP in 2014 in its

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decision on whether to solely pursue an on-site landfill, as opposed to utilizing an off-site facility for managing some portion of the CCR. As such, page 21, lines 9 through 14, of our original testimony, should be rewritten as follows:

> "disposal around July of 2016. Using DEP's stated production rate of 200,000 tons per month for the on-site landfill; the ~~5.4~~ 6.3 million tons of ash could be excavated and disposed in the landfill in about ~~27~~ 32 months, with a completion date for ash excavation would be around ~~October~~ March 201~~8~~9. This would also provide a reasonable contingency of approximately ~~nine~~ four months to the August 2019 closure deadline."

Q. **DOES THIS CHANGE AFFECT YOUR CONCLUSIONS OR RECOMMENDATIONS REGARDING THE FEASIBILITY OF THE SUTTON ON-SITE GREENFIELD LANDFILL TO HAVE BEEN CONSTRUCTED AND OPERATED IN A TIMEFRAME THAT ALLOWED FOR COMPLIANCE WITH THE AUGUST 1, 2019, CLOSURE DEADLINE FOR HIGH-PRIORITY SITES UNDER THE COAL ASH MANAGEMENT ACT (CAMA)?**

A. No. Our conclusions and recommendations on this issue remain the same.

Q. PLEASE DESCRIBE THE CHANGES THAT YOU ARE MAKING REGARDING THE QUANTITY OF CCR AT THE ASHEVILLE PLANT.

A. On page 27, lines 14 and 15, of our direct testimony, we stated that the net quantity of CCR excavated from the site was 113,000 tons, based on calculations in G&M Exhibit 6. This calculation was based on responses received from DEP regarding the quantities of CCR in the 1982 and 1964 basin on January 1, 2015, as compared to January 1, 2017, along with consideration of production ash and the quantity of CCR taken to the Asheville Airport structural fill site. In his rebuttal testimony, DEP witness Kerin testified that DEP had moved approximately 850,000 tons off-site, not including the Airport structural fill project. In follow-up discussions with DEP on November 14, 2017, as well as supplemental information filed by DEP on November 16, 2017, we now understand that DEP asserts additional quantity of CCR was excavated and removed offsite than was estimated to have been located within the 1982 basin, and DEP provided additional tracking records, invoices, and purchase orders to support the materials removed from the site.

Q. DOES THIS CHANGE AFFECT YOUR RECOMMENDED ADJUSTMENT FOR THE ASHEVILLE PLANT?

Q. PLEASE EXPLAIN YOUR CONCERN OVER THE COST OF THE CCR MOVED FROM THE 1982 BASIN TO THE ASH STACK IN THE 1964 BASIN.

A. In our direct testimony, we recommended inclusion of only those costs that were associated with excavation of the CCR and stockpiling, but not the costs associated with loading into the truck and placement in the Ash Stack. The basis for this position was that it would have been more cost-effective for DEP to have immediately transported the CCR off-site, rather than creating an Ash Stack in the 1964 Basin. This double-handling of CCR increased costs and also complicated further closure options for the 1964 Basin. We continue to support our original position that only the costs associated with the initial excavation and loading of the CCR should be recoverable.

Q. PLEASE EXPLAIN YOUR CONCERN OVER THE ASH PROCESSING COSTS DEP INCURRED FOR PRODUCTION ASH HANDLING AND FOR THE REMAINING CCR EXCAVATED FROM THE 1982 BASIN AND DISPOSED OF OFF-SITE.

A. In our direct testimony, we utilized DEP's contracted off-site disposal rates signed in December 2016 with Waste Management of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton as the basis to calculate the reasonableness of costs incurred by DEP to dispose of only that portion of CCR we could reconcile from DEP's estimate of CCR quantities on the site. At that time, we could not determine the reasonableness of the overall costs, since were not able to validate one of the critical inputs: the total quantity of CCR being removed from the site. Based on the revised quantities, the transportation costs incurred by DEP for the hauling of CCR to the DEC Cliffside landfill appear excessive compared to the transportation costs on a per-mile basis associated with the Waste Management contract and truck hauling contracts entered into by DEP at other facilities. Further, due to the closer proximity of the Cliffside landfill to the Asheville facility (approximately 60 miles one-way) as compared to the R&B landfill in Homer, Georgia, (approximately 128 miles one-way), as well as the higher tipping fees associated with the R&B landfill relative to the placement fee for the Cliffside landfill, DEP should have exclusively utilized the Cliffside landfill to handle the CCR disposed off-site from the Asheville facility. Using this analysis, we calculate a revised transportation and placement cost on a per-ton basis of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton.

Q. PLEASE DESCRIBE THE CHANGES THAT YOU ARE MAKING TO G&M EXHIBIT NO. 6 AND SUPPLEMENTAL EXHIBIT NO. 8.

A. Instead of utilizing the tonnage reports originally provided by DEP prior to filing our testimony to determine the amount of CCR removed from the site, we are instead utilizing the tons of CCR removed from the site reported by DEP in data responses provided after the filing of our direct testimony. The Revised Exhibit No. 6 incorporates the currently understood CCR quantities DEP reports were removed from the site.

Supplemental Exhibit 8 applies the revised transportation and placement rate described above to the CCR materials that we now understand DEP removed from the Asheville site in 2015 and 2016, other than quantity placed at the Airport structural fill site. In addition, the Supplemental Exhibit 8 includes the recommended adjustment to disallow the costs associated with moving CCR from the 1982 Basin to create the Ash Stack in the 1964 Basin.

Q. HOW DO THESE CHANGES AFFECT YOUR RECOMMENDED ADJUSTMENT FOR THE ASHEVILLE FACILITY?

A. The recommendation to disallow the costs associated with moving CCR from the 1982 Basin to create the Ash Stack in the 1964 Basin results in a recommended disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This adjustment is consistent with our initial analysis. The recommendation to utilize the revised off-site disposal rate described above results in a recommended disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** Combined, these two adjustments total

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$29,373,052, which represents a significantly smaller adjustment than the adjustment of $45,647,748 included in our direct testimony.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

BY MR. DODGE:

Q. Mr. Moore and Mr. Garrett, did you prepare a summary of your testimony?

A. (Vance Moore) Yes.

Q. Would you please provide it at this time?

A. Good afternoon, Mr. Chairman, Commissioners. The purpose of our testimony is to make recommendations to the Commission on the Public Staff's position regarding whether Duke Energy Progress, LLC, or DEP, prudently incurred costs with respect to coal ash management. Our review was focused on the actions taken by DEP to comply with applicable state and federal laws governing coal ash basin closure.

In our investigation, we evaluated the closure methods and costs incurred at all of DEP's facilities. We did not take exception to DEP's selected closure method for the coal ash ponds at Roxboro and Mayo, nor did we take exception to DEP's selection of coal ash basins located at Cape Fear and H.F. Lee, which were deemed intermediate risk, as sites for cementitious beneficiation projects. In addition, we did not take exception to DEP's selected closure method for the coal ash ponds located at Weatherspoon, which were deemed intermediate risk. We did question whether DEP could make additional efforts to increase the annual tonnage being removed from Weatherspoon for beneficial reuse for cementitious purposes, so that it would qualify as the third beneficiation site, thus eliminating the need for a beneficiation project at Buck Station and the substantial cost premium forecasted as compared to other closure options at Buck.

For the coal ash ponds at Asheville and Sutton, which were deemed high priority, the closure method of excavation, removal, and disposal of ash in a lined landfill or lined structural fill was prescribed by law. For Sutton, our testimony demonstrated that, if DEP would have pursued the on-site landfill on the same start date as DEP pursued the development of the Brickhaven structural fill project, DEP could have complied with CAMA timelines and avoided substantial transportation costs. The hauling of approximately 2 million tons of ash to Brickhaven was not reasonable or prudent. Therefore, we and the Public Staff recommend that the Commission disallow $80.5 million of DEP's request for recovery.

For Asheville, DEP had considered development of an on-site landfill prior to the passage of CAMA and as far back as 2007. In our testimony, we take exception that DEP was unable to provide reports or documents demonstrating that an on-site landfill was not feasible, knowing the substantial costs involved in transporting ash off site. In addition, our testimony raises questions as to whether DEP sufficiently understood the quantity of ash that existed in the 1982 basin. When comparing the ash quantities reported to the cost incurred for ash processing, we were left to conclude that DEP's actions were not reasonable and prudent, and thus recommended an adjustment for the ash processing costs. We and the Public Staff recommended that the Commission exclude $45.6 million from the rate base.

The purpose of our supplemental testimony is to make a correction to our direct testimony regarding the quantity of CCR located at the Sutton plant as of January 1, 2015. In addition, our supplemental testimony makes revisions to portions of our testimony related to the Asheville site based on supplemental information provided by DEP. This information provided after the filing of our testimony in response to earlier Public Staff data requests, along with the rebuttal testimony of DEP Witness John Kerin, modified our understanding of the amount of CCR on which our direct testimony was based.

With regard to Sutton, the correction in our testimony is based on updating the quantity of CCR located at the Sutton facility as of January 1, 2015, to 6.3 million tons. This increased CCR tonnage does not, however, change our conclusions or recommendations regarding the feasibility of the Sutton on-site greenfield landfill to have been constructed and operated in a time frame that allowed for compliance with the August 1, 2019, closure deadline.

With regard to Asheville, our supplemental testimony is based on additional ash tracking records, invoices, and purchase orders provided by DEP to support our acceptance of increasing the quantity of CCR disposed at the Cliffside landfill and R&B landfills to 828,500 tons.

We still have continued concerns, however, about the cost paid by DEP for processing ash at the Asheville site. Specifically, we continue to support our original position that no costs for loading and hauling associated with the on-site stockpiling or stacking of ash should be recoverable. Further, DEP should have exclusively utilized the Cliffside landfill in lieu of the R&B landfill in Homer, Georgia, due to the closer proximity and the lower cost of the Cliffside landfill.

We have revised G&M Exhibit 6 in our testimony to reflect the new tonnage information provided by DEP. We have also included a supplemental Exhibit 8 that applies the per-ton rate applicable for the off-site disposal based on the per-mile basis from the Waste Management contract to the distance hauled to Cliffside and utilized the ash placement costs associated at Cliffside as opposed to the tipping fee at the R&B landfill. These changes result in a modified recommended disallowance of $29.3 million for the Asheville facility, which represents a significantly smaller adjustment than the adjustment of $45.6 million included in our October 20, 2017, testimony.

In summary, we and the Public Staff recommend that the Commission disallow $109.8 million of costs incurred by DEP related to the disposal of coal combustion residuals.

This completes our summary.

Q. Thank you.

MR. DODGE: The witnesses are available

for cross examination.

CHAIRMAN FINLEY: Mr. Quinn.

CROSS EXAMINATION BY MR. QUINN:

Q. Mr. Moore, Mr. Garrett, good afternoon. I don't know who to direct my questions to, so I will direct it to both of you, and whoever you feel is the appropriate person, please answer. I want to talk to you about a line on page 1 of your testimony summary that you just read, line 7 and 8. You said, "We did not take exception to DEP's selected closure method for the coal ash ponds at Roxboro and Mayo," correct?

A. (Vance Moore) That is correct.

Q. Were either of you gentlemen present for the testimony of Mark Quarles on Friday?

A. (Bernard Garrett) No.

Q. Did either of you gentlemen read Mr. Quarles' prefiled direct testimony?

A. Yes.

Q. So then I guess you probably understand that Mr. Quarles disagrees with the Company's plan to close these impoundments and use a cap; are you familiar with that disagreement?

A. (Vance Moore) Yes.

Q. So have you two gentlemen done a study of the site-specific details of the coal ash impoundments at Roxboro and Mayo?

A. (Bernard Garrett) No.

Q. So you haven't studied any facts specific to the two sites, any independent reports related to the impoundments at those sites, anything like that?

A. We did not complete our own study, but we have reviewed relevant reports.

Q. Okay. So based on your review of relevant reports, are you familiar with the fact that there are exceedances of 2L standards in the groundwater downgradient of the coal ash impoundments at Roxboro and Mayo?

A. (Vance Moore) Yes.

Q. Okay. And are you also familiar with the fact that, as these impoundments exist presently, groundwater comes into contact with the bottom of the impoundment at the Roxboro and Mayo sites; are you familiar with that?

A. Yes.

Q. And you are familiar with the fact that, if these impoundments are closed using a cap and the coal ash is left in place, the groundwater will continue to remain in contact with the coal ash at the bottom of several impoundments at Roxboro and Mayo?

A. Yes.

Q. Okay. So doesn't that -- wouldn't it be more protective of groundwater to, instead of leaving the coal ash in these impoundments at the site, to instead excavate the coal ash and remove it off site?

A. I think one could argue that it could be more protective. I believe it was our direction to review whether or not the selected closure method was in compliance with the CAMA and CCR regulations and other laws and regulations.

Q. So it sounds like, then, what your testimony is, is that it may comply with CAMA, but that it would be more protective of the environment to take the coal ash and to move it off site; is that fair?

A. I think that you could say that's a potential result. I don't think that I could say that it's an absolute result.

MR. QUINN: All right. I have no more questions.

CHAIRMAN FINLEY: Who is next? Anybody over here?

CROSS EXAMINATION BY MR. BURNETT:

Q. Good afternoon, gentlemen. Sorry I'm talking to the side of your head. Good to see you again. First, I can't believe you made a lawyer do math on the fly with that correction, so that was rough. But anyhow, gentlemen, you would agree with me that your investigation in this matter was both reasonable and properly scoped, don't you?

A. (Bernard Garrett) Yes.

Q. And you agree with me that the scope of your investigation in this matter was to determine whether the Company chose the least-cost method of achieving compliance with the laws and regulations governing coal ash management; isn't that right?

A. Yes.

Q. And you would agree with me that the scope of your investigation, as I just described it, is the right way to conduct an investigation, because once those laws that you are talking about are in place, the Company has to comply with them, don't they?

A. Yes.

Q. And you also agree with me that the scope of your investigation in this matter is correct and proper because it focuses on actual issues in this case that the Company has presented, which are whether the Company's coal ash costs are reasonable and prudent, correct?

A. Yes.

Q. You agree with me that, to have a valid opinion as to whether the Company has selected the least-cost method in achieving compliance, you need to review each individual basin that the Company has, just like you guys did, correct?

A. Yes.

Q. And you also agree with me that, to have a valid opinion on whether the Company has selected the least-cost compliant options, you need to submit and review extensive discovery on both the technical and financial support for the Company's decisions, just like you guys did; isn't that right?

A. Yes.

Q. In addition to written discovery, you agree with me that you had in-person meetings and telephonic conferences with Company personnel when you had questions; isn't that right?

A. Yes.

Q. And in the course of your investigation, you actually visited some of our basins, inspected them, took a look around, asked questions of our personnel, didn't you?

A. Yes.

Q. I think you would also agree with me that, in coming to your conclusions in this case, you guys looked at actions taken by the Company to comply with applicable state and federal regulatory requirements, not on settlement or litigation outcomes; isn't that right?

A. Yes.

Q. And you also agree with me that, in forming your opinions in this case, you did not recommend your disallowances based on any ratios, did you?

A. Not the specific disallowances of our testimony.

Q. And you didn't use ratios of disallowances in your conclusions, because doing so is a shortcut, isn't it?

A. We did not take that approach.

Q. Right. But I think you used that exact word, that using ratios is a shortcut approach; isn't that right?

A. (Vance Moore) I don't recall where we stated that. Maybe you could remind me.

Q. Yes, sir. Give me one second to see if I could pull this up here on the screen. While we are doing that, it's testimony page 35, lines 7 through 10.

You see there it says, "However, because our analysis depended on the review of individual expenditures, we do not attempt the shortcut approach of recommending a 2017 disallowance based on the same ratio of disallowances"; do you see that there?

A. (Bernard Garrett) You are referring to a comparison of the 2015/2016 disallowances to something that would have occurred in 2017.

Q. Yes, sir. I think that's what your testimony suggests there.

A. Yes.

Q. I just want to make sure I read that right. When you talked about using ratios, your words were that that was a shortcut approach there in your testimony.

A. (No response.)

Q. I'm not saying you used shortcuts. I'm saying that you didn't.

A. That's right.

Q. Okay. Shifting topics a little bit, you agree with Mr. Kerin's general characterizations in his testimony of applicable federal and state regulations addressing the management and closure of CCR units in

North and South Carolina, correct?

A. (Vance Moore) Yes.

Q. And you said this in your summary, but I'm just gonna go through them just to make sure I had it right. You don't take any exception to the Company's selected closure method for the basins at the Robinson unit?

A. That's correct.

Q. Or the Mayo site?

MR. QUINN: Objection, sweetheart cross.

CHAIRMAN FINLEY: Beg your pardon?

MR. QUINN: It sounds like sweetheart cross to me.

CHAIRMAN FINLEY: Overruled.

BY MR. BURNETT:

Q. Or the Roxboro site, which I think we've explored earlier with Sierra Club?

A. That's correct.

Q. Or Cape Fear?

A. Correct.

Q. Or H.F. Lee?

A. Correct.

Q. Or Weatherspoon?

A. Correct.

Q. Now, with respect to Sutton, I believe we've talked about this. You've heard Mr. Dodge and Mr. Kerin talk about this earlier. It's in your summary.

One of your positions with Sutton is that the Company should have built a landfill on that site sooner than it did; isn't that right?

A. That is correct.

A. (Bernard Garrett) Yes.

Q. Okay. Now, in your supplemental testimony -- I just want to make sure I had that right -- you were carrying in your supplemental testimony -- I'm sorry, in your original position, you had put in a nine-month contingency to build that landfill on Sutton under your proposal. I just want to make sure I got that right, that went down to a four-month contingency, as we see up there, under your supplemental; is that right?

A. Yes, that is correct.

Q. Okay. And although I realize we have -- you have other opinions regarding Asheville, you also, like you said in your summary, believe that the Company could have built an on-site landfill at the Asheville site, correct?

A. (Vance Moore) I don't believe that's exactly what we said. I believe that we said that the Company should have evaluated and eliminated it as an option, and we did not see where it had been specifically eliminated as an option.

Q. Okay. I just -- that may be my confusion, because if I'm looking at your testimony there on page 28, lines 12 through 17, it said, "Had an on-site industrial landfill capable of storing 3 million tons of CCR been pursued," and we are talking about Asheville here in that section, "costs could have potentially been avoided."

I just want to make sure that I see the word "potentially" in use there. If you are saying you don't know one way or the other but "could have been," I could accept that and move on.

A. (Bernard Garrett) The $90 million we are referring to there is potential future cost avoidance for ash associated with the '64 basin.

Q. Okay. So just to make sure I understand that, nothing that's happened now, something that may happen in the future; you are just giving us the heads up on that?

A. Yes.

Q. Okay. Now, for the Asheville site, you mention in your summary that you had an opportunity to sit down with the Company when you had questions about ash quantity there, and you asked the Company your questions, you got some clarification, and you got the information -- some more information that you needed through those discussions; isn't that right?

A. Yes.

Q. Okay. And you also mentioned that in your summary, as a product of those discussions that you had with the Company, your original Asheville disallowance of about $45 million got reduced down to about $29 million, correct?

A. Correct.

Q. And you would agree with me that, while we can still agree to disagree about that $29 million, the point there is that, when you had a question about the Company's data, you didn't say, well, I just didn't get what I needed, or I don't understand, and throw your hands up; you sat down and talked to us when you had those questions, didn't you?

A. Correct.

Q. Now, further with the Asheville site, I think I understand that, in your supplemental testimony, you say that approximately 558,000 tons of ash should have been moved from the Asheville site to the Cliffside site; isn't that right?

A. (Vance Moore) I believe that what we said is that it should not have been moved from the '82 basin into the '64 basin, resulting in a need to double-handle it to ultimately, I guess, provide the final solution for that ash.

Q. Okay. Well, I'm gonna go ahead and hand out -- I know everyone has it, but I'm going to hand out, just so everyone can see it, a copy of your Supplemental Exhibit 8, just so we could look at it. I'm gonna hand out the confidential copy so the parties here at the table and the Commissioners can see that. I do not intend, though, gentlemen, to talk about any of the confidential information here on there. If you would do the same for me, just make sure we don't slip in any of that.

MR. RUNKLE: Chairman, can the record reflect that I have not received a copy of this and did not sign a confidentiality agreement?

CHAIRMAN FINLEY: Yes, you can. The record will reflect that.

MR. RUNKLE: Thank you.

MR. BURNETT: And Mr. Chairman, a redacted copy is right up there. Again, I'm not going to get into any of the numbers, but if Counsel turns around, they can see the redacted copy there.

BY MR. BURNETT:

Q. So if I'm reading your items number 3 and 4 on that correctly, if I take the quantity of ash there, that 374, and the quantity of the ash of 184 in items 3 and 4 and add them together, that's where I'm getting that 558 from; am I right there?

A. Correct.

Q. Okay. And then if I go down to Footnote 8 that I see at the bottom of that page, it says that your position is that that material should have been moved to the Cliffside basin?

A. Correct.

Q. Okay. So you also agree with me, and I believe it's reflected right there in your Footnote 6, that the round-trip distance from Asheville to Cliffside is about 120 miles, correct?

A. Correct.

Q. And you would agree with me, wouldn't you, that the ash from Asheville to Cliffside has to be moved by truck, because there is not a developed train infrastructure there to move that ash, correct?

A. I can't confirm or deny the rail line, but my analysis was based on truck traffic.

Q. Okay. That 120 was based -- 120 miles was based on truck, okay.

Will you -- now, I'm getting way out of my expertise here, but would you accept that the average weight payload capacity of the kind of trucks we use to haul that ash is about between 17 and 20 tons?

A. I believe that I have information from purchase orders that direct it to be a different number.

Q. Okay. Well, do you dispute that your typical tri-axle dump truck that's street legal has a 14.5- to 16-point ton payload capacity?

A. (Bernard Garrett) I don't believe that was part of our analysis.

Q. I don't either, but I'm just asking, do you have any reason to believe that's inaccurate?

A. (Vance Moore) Subject to check.

Q. Okay. And subject to check, would you agree with me that a quad-axle dump truck has about a 17- to 19.5-ton capacity?

A. Subject to check.

Q. And one last one, just subject to check, we are not talking about a Terex TA articulated dump truck that has payload capacities of 60,000 pounds, because those aren't street legal in North Carolina, are they?

A. Correct. Our analysis is based on trucks that were ready to go on highways.

Q. Okay. Well, if you accept -- I will take your 558,000 tons of ash, and if I divide that by 18.5 tons of payload, again, subject to check, that you've accepted, would you agree with me that, subject to check on my math, that's 30,162 truckloads that need to be moved from Asheville to Cliffside?

A. Subject to check.

Q. Okay. And subject to check, would you accept for me that -- accept from me that that 30,162 truckloads, driving 120 round-trip miles from Asheville to Sutton, yields 3,619,440 miles of driving?

A. Asheville to Sutton or Asheville to Cliffside?

Q. I'm sorry. I've got Cliffside on the mind -- Sutton on the mind. Asheville to Cliffside.

A. Subject to check, yes.

Q. And I'm not asking you this question to be cute. I just want to put this distance into perspective that folks can understand.

Would -- subject to check, if you accept that the circumference of the planet earth is about 25,000 miles, would you agree with me that that amount of driving equals about 145 trips around the earth?

A. Subject to check.

Q. You agree with me that, in a given month, if I'm hauling ash, it's reasonable for me to assume -- reasonable for me to assume 21.6 days of working in a month -- because I want to give my truck drivers weekends off -- I don't want to make them work 31 days a week, do I -- or a month?

A. Correct.

Q. Okay. And an eight-hour day for my truck divers would be reasonable?

A. (Bernard Garrett) I believe it was higher than that in the purchase orders, perhaps 10.

Q. Okay. Give me plus or minus 8 to 10 on that. So if I assume that I'm moving that ash, I think I'm gonna have to move, subject to check again, 4,292 tons of ash per day, which means 232 trucks per day, which equals 29 trucks per hour, which means that a truck has to leave the Asheville site fully loaded, washed, weighed, and cleared every two minutes for six months; does that sound about right?

A. (Vance Moore) I would like to confirm how many days you did your calculation over, and what was the starting date and the ending date, for the number of dates you used in your calculation.

Q. Yes, sir. That's a six-month period.

A. And what is the six-month basis based on?

Q. I feel like I better raise my hand here, but I got you. That's a fair question.

You heard the testimony earlier that a combined cycle plant is being built at the Asheville site; isn't that right?

A. Correct.

Q. You heard Mr. Kerin give testimony earlier that certain areas of that site had to be turned over to plant construction at a given time for that plant construction to stay on schedule, correct?

A. Correct.

Q. You have not issued any opinion on the timing schedule or construction of that combined cycle in this case, have you?

A. Not on the construction of the combined cycle.

Q. So you don't know if -- what times I would have had to turn over laydown areas or areas of the

Asheville site to the product construction team, right?

A. Based off information submitted by DEP, I believe that we understand that -- and we accept that it needed to be turned over in the vicinity of October of 2016.

Q. Okay. Well, I think my final questions, as we sit here today, I guess you just -- you just made another change to Garrett & Moore Revised Exhibit 6, and you changed your quantities here on the stand, and I'm not criticizing you for that. I'm just saying that we should make sure that we have got all our numbers and all our assumptions right before we start talking about the $109 million worth of disallowance, shouldn't we?

A. As long as I understand what we have changed.

MR. BURNETT: Yes. Thank you. That's all I have.

CHAIRMAN FINLEY: Redirect?

MR. DODGE: Just a couple. Thank you, Mr. Chairman.

REDIRECT EXAMINATION BY MR. DODGE:

Q. Regarding the questions about the Mountain Energy Act that was just mentioned and the combined cycle facility, subject to check, would you agree that the Mountain Energy Act was passed -- was enacted by the General Assembly in June 2015?

A. (Vance Moore) Yes.

Q. And so the -- if we are using that as a starting point, then six months, as Mr. Burnett used for his calculation of the mileage, would be too short a period of time to the October 2016 date you entered that the facility had to be handed over?

A. My analysis is not based on six months.

Q. And is it your understanding that Duke Energy Progress was hauling ash from the Asheville facility much earlier than that in 2015 and prior to, in 2014 as well?

A. Correct.

Q. What information do you have regarding where that -- where they were hauling materials prior to January 2015?

A. It's my understanding, prior to January 2015, ash was being removed from the 1982 basin and taken to the Asheville Airport project.

Q. Okay. And so there is -- I'm not gonna try to do any math over any specific time frames. There is a much larger window of time over which your position is based on the movement of that ash from one facility to another; is that correct?

A. That is correct.

Q. Okay. Thank you. Mr. Burnett also asked you about the average tonnage for the vehicles that were moving this material.

What was the basis for the estimate that you used in your analysis?

A. I am referring to a Duke Energy purchase order, Maximo purchase order number, I believe, is 1380566. I'm on page 2.

Q. Well, and can you just provide the average tonnage that you were using for your analysis?

A. It says, "Seller to provide the following number of trucks per the schedule below," and it says, "Averaging 21 tons per truck and making one turn per dayshift."

Q. Thank you. Mr. Burnett also asked you about your testimony on page 28, and he showed on the screen a quote regarding the -- your position on an on-site landfill at the Asheville facility.

Could you turn to page 28 in your testimony?

A. (Witness peruses document.)

Q. And he had language up there to line 13 -- let me know when you get there. Sorry.

A. (Witness peruses document.)
It's direct?
Q. Your direct, yes. Sorry about that.
A. (Bernard Garrett) Page 28?
Q. Page 28?
A. (Vance Moore) Yes.
Q. And he asked you about a quote starting on line 12, but I just wanted to read the sentence just prior to that, starting on line 10 through line 12. Could you read the sentence that you state there starting with, "It does," line 10?
A. "It does not appear DEP evaluated or identified fatal flaws eliminating the possibility of an on-site industrial landfill."
Q. Okay. And so is it your position that the Duke -- DEP did not provide sufficient information or evidence that it was not feasible to build an on-site landfill at the Asheville facility?
A. Yes.
Q. Thank you. Mr. Quinn asked you a few questions about the Roxboro and Mayo facilities, and you indicated you didn't conduct -- it was beyond the scope of your analysis to conduct separate reviews of the groundwater modeling that was done for those

closure plans.

Did you review reports, the information that was provided by DEP, or did you have personnel, hydrogeologists on your staff review that information?

A. (Bernard Garrett) Yes.

Q. And they provided information that they thought the assumptions in that modeling was reasonable at this time?

A. Yes.

Q. And also, is it your understanding that those plans for the Roxboro and Mayo facilities, the closure plans, are finalized or being implemented at this time for those facilities?

A. I believe they refer to them as the SARPs, the site analysis and removal plans, and those are still in development at this time. They have not been finalized, as far as I know.

Q. And Mr. Kerin -- you were present when Mr. Kerin was testimony -- testifying earlier today?

A. Yes.

Q. And he indicated that the costs in this case are tied to the maintenance and the development of those plans, but not implementing a closure plan at Roxboro and Mayo at this time?

A. Yes.

MR. DODGE: Thank you.

CHAIRMAN FINLEY: Questions by the Commission?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Gentlemen, I'm still not sure I fully understand the scope of what you concluded about the SARPs at Roxboro and Mayo. I thought I heard your answer to Mr. Quinn's question to say that you reviewed them to determine whether they were the lowest cost methods of complying with CAMA and the CCR rule; did I hear that correctly?

A. (Bernard Garrett) Which reports are you referring to?

Q. The site assessment remediation reports from Roxboro and Mayo. You reviewed those plans?

A. Yes, sir. The site assessment reports --

Q. Right.

A. -- are basically, like, groundwater models of the sites as they exist today.

Q. Okay.

A. And then they are revised to predict the outcomes of different closure methodologies. They don't -- they don't necessarily have cost information in them.

Q. They do not have cost information in them?

A. Not those specific reports.

Q. All right. What about your review of the selected -- preliminary selected closure plan for those basins? Did you have cost information on that?

A. Yes.

Q. Did you have cost information on alternative means of closing those basins, other than the one preliminarily selected?

A. No. We only had cost information, I believe, at Roxboro for the preliminary selection.

Q. Okay. That's taking me somewhere different than I wanted to get, so let me get back to -- what I was really trying to focus on was the scope of what you were examining. You were examining the preliminarily selected plan to determine whether it was a reasonable and prudent method of complying with CAMA and CCR; is that correct?

A. Yes, sir. That's a fair summary.

Q. Well, then, this is the question I really want to be sure I'm clear about.

Did you review those preliminary closure plans to determine whether they were reasonable and prudent plans to ensure long-term, ongoing compliance with the Clean Water Act and the 2L drinking water standards?

A. (Vance Moore) I'm concerned with the word "ensure," because there is ongoing analysis.

Q. Pick your word. I'm just trying to figure, did you do the analysis of compliance with those two regulatory regimes?

A. I did not do an analysis independently that said that I believed that their selected closure method would ensure long-term compliance with all other standards, 2L or otherwise. What I did review is reports prepared by their consultants which did modeling of the selected closure method, and it was to my satisfaction that the selected method could not be ruled out.

Q. Are the reports that you reviewed -- do you know if they have been put into the record for the case, or were they part of the discovery -- they were part of the discovery, clearly; you reviewed them?

A. Yes, sir.

Q. Do you know if they have been offered in the record as an exhibit to any of the witnesses' testimony?

A. I don't know.

A. (Bernard Garrett) I don't recall if they have been.

COMMISSIONER CLODFELTER: Mr. Chairman, if they have been, I would ask Counsel to just give me the reference. All I'm looking for is the reference.

MR. BURNETT: Yes, sir.

COMMISSIONER CLODFELTER: Thank you. That's all. Thank you, gentlemen.

CHAIRMAN FINLEY: Questions on the Commission's questions? Questions on the Commission's questions?

MR. BURNETT: No, sir. I'm sorry.

CHAIRMAN FINLEY: All right, gentlemen. Thank you. You may be excused and we will accept the exhibits into evidence.

(Whereupon, G&M-1 through G&M-7, G&M Revised Exhibit 6, and G&M Supplemental Exhibit 8 were admitted into evidence.)

CHAIRMAN FINLEY: Take a recess and come back at 3:55.

(Whereupon, a recess was taken from 3:38 p.m. to 3:51 p.m.)

CHAIRMAN FINLEY: All right, Mr. Drooz. Mr. Maness and Mr. Lucas are your witnesses, Mr. Drooz?

MR. DROOZ: Yes. Public Staff calls Mr. Maness and Mr. Lucas to the stand.

MICHAEL MANESS and JAY LUCAS,
having first been duly sworn, were examined
and testified as follows:

DIRECT EXAMINATION BY MR. DROOZ:

Q. Mr. Lucas, would you please state your name and position for the record?

A. (Jay Lucas) Jay Lucas. I'm an engineer with the Public Staff's electric division.

Q. And on October 20, 2017, did you cause to be prefiled in this proceeding 73 pages of direct testimony, including confidential portions, a one-page appendix summarizing your qualifications, and Exhibits 1 through 9?

A. Yes.

Q. And on November 15, 2017, did you cause to be prefiled in this proceeding four pages of supplemental testimony and Revised Exhibits 5 and 6?

A. Yes.

Q. Do you have any corrections to your prefiled testimonies or exhibits?

A. Yes. In the summary, I left out my recommendation for equitable sharing.

Q. What page is that?

A. (Witness peruses document.)

Page 62.

Q. Is your summary on page 3 of your direct prefiled testimony?

A. Yes.

Q. Okay. Do you have any other corrections or changes?

A. No.

MR. DROOZ: Mr. Chairman, the Public Staff moves the prefiled testimony of Mr. Lucas be admitted into the record as if orally given from the stand, and that his exhibits be marked for identification as indicated on the prefiled copies.

CHAIRMAN FINLEY: Mr. Lucas' 73 pages of testimony and his appendix are copied into the record as though given orally from the stand, and his nine exhibits are marked for identification as premarked in the filing.

(Whereupon, Direct Lucas Exhibits 1 through 9 and Supplemental Revised Lucas

Exhibits 5 and 6 were marked for identification.)

(Whereupon, the prefiled direct and supplemental testimony of Jay Lucas was copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF JAY LUCAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Testimony of Jay Lucas

On Behalf of the Public Staff

North Carolina Utilities Commission

October 20, 2017

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

A. My name is Jay Lucas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Commission the Public Staff's position on the following topics in the general rate case filed by Duke Energy Progress, LLC (DEP or the Company), in Docket No. E-2, Sub 1142, on June 1, 2017:

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1. Whether the Company reasonably and prudently incurred the costs of constructing the Zero Liquid Discharge (ZLD) system at the Mayo Plant.
2. Whether the Company should be permitted to recover the costs of disposing coal ash from the Sutton Plant at the Brickhaven facility through the fuel clause, G.S. 62-133.2(a1)(9).
3. Whether the Company reasonably and prudently incurred the costs of managing coal ash.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. As described in more detail below, I make the following recommendations:

1. Exclude $34.3 million from rate base related to Mayo Plant ZLD construction delays and cost overruns.
2. Exclude certain coal ash disposal costs from the fuel clause, G.S. 62-133.2(a1)(9), because they are not a sale of coal combustion by-products.
3. Recognize that it is appropriate as a ratemaking principle to exclude (1) DEP litigation costs in cases where there are environmental violations; (2) costs to remedy environmental violations where the costs exceed what CAMA would have required in the

absence of environmental violations; and (3) costs required to be excluded under the probation conditions of the federal plea agreement. Within these categories, exclude the particular costs identified to date, as set out below.

MAYO POWER PLANT - ZERO LIQUID DISCHARGE SYSTEM

Q. PLEASE DESCRIBE DEP'S MAYO PLANT.

A. DEP's Mayo Plant is a single unit, subcritical, pulverized coal-fired facility with a winter operating capacity rating of 746 megawatts, located near Roxboro, North Carolina. It became operational in 1983. Originally designed and operated as a baseload generating unit, Mayo is now classified by DEP as an intermediate generating unit, as evidenced by the fact that its annual capacity factor has been below 50% since 2012. Its monthly capacity factor exceeded 60% for only seven of 55 months (January 1, 2013 through July 31, 2017), compared to 37 of the previous 55 months (June 30, 2008 through December 31, 2012). A 60% annual capacity factor has traditionally been the dividing line between intermediate and baseload designation.

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Q. WHAT IS A ZLD SYSTEM?

A. A ZLD system treats wastewater from various sources by heating it and evaporating most or all of the water, concentrating pollutants into a much smaller volume of waste such as dry crystals (complete ZLD) or a thick brine solution (partial ZLD). The smaller volume of waste allows for disposal methods such as landfilling that would not be possible for a high volume of wastewater. The Mayo Plant uses steam extracted from its generator turbine to provide heat to a partial ZLD system that treats one of its wastewater streams. I will describe the ZLD system at the Mayo Plant in more detail later in my testimony.

Q. PLEASE DESCRIBE THE ENVIRONMENTAL PROTECTION CONTROLS AT DEP'S MAYO PLANT PRIOR TO THE INSTALLATION OF THE ZLD SYSTEM.

A. In 2002, the General Assembly enacted G.S. 143-215.107D, the North Carolina Clean Smokestacks Act (Session Law 2002-4), which put tighter limits on the emission of nitrogen oxides and sulfur dioxide into the air. Electric utilities then undertook steps to comply with the Act, including installation of flue gas desulfurization (FGD) systems, which use limestone mixed with water to absorb sulfur dioxide. The wastewater created by this process must be disposed of properly in order to prevent violations of a power plant's National Pollutant

Discharge Elimination System (NPDES) permit, which sets limits on wastewater discharged to the waters of the State. The Mayo Plant received an NPDES permit from the North Carolina Department of Environment and Natural Resources (NCDENR, now NCDEQ or DEQ) in May 2007, setting water quality limits on the discharge of wastewater from the coal ash basin to the Mayo Reservoir. This permit included additional limits applicable to the FGD system wastewater. In 2008, DEP (then known as Progress Energy Carolinas, Inc.) began a series of studies on FGD system wastewater from the Mayo Plant, as well as at the nearby Roxboro Plant, in order to determine the potential effects of FGD system wastewater on the surrounding environment. In July 2009, DEP began operation of its FGD system at the Mayo Plant and, as a result of the wastewater environmental impact study, installed a bioreactor to treat the FGD wastewater before discharging the wastewater into the coal ash basin, which then discharged into the Mayo Reservoir. The bioreactor used specialized microscopic organisms to remove potential pollutants from the FGD system wastewater. In October 2009, NCDENR renewed the NPDES permit for the Mayo Plant and added discharge limits for antimony, boron, and molybdenum.

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Q. PLEASE DESCRIBE THE SERIES OF EVENTS THAT LED TO THE NEED FOR THE MAYO ZLD SYSTEM.

A. After the FGD system became operational, the treated wastewater discharge from the coal ash pond was found to violate the NPDES limits in the Mayo Plant's October 2009 permit. Some of the violations were attributable to the FGD system wastewater, despite treatment of the wastewater by the bioreactor. DEP's research and analysis revealed that a partial ZLD system was the best solution for satisfactorily treating the FGD system wastewater. With the partial ZLD system, DEP believed that it could combine the concentrated brine from the partial ZLD system with dry production fly ash from coal combustion and place the combined mixture in a landfill. The clean water created by the evaporation process then could be used at the Mayo Plant. In June 2012, DEP and NCDENR entered into a Special Order By Consent (SOC) that gave DEP what it believed to be the necessary time to design and construct the partial ZLD without being subject to large penalties for NPDES permit violations.

Q. DO YOU AGREE WITH DEP'S CHOICE OF A PARTIAL ZLD SYSTEM TO ADDRESS THE WASTEWATER PROBLEMS AT MAYO?

A. Yes. Based on my evaluation, I believe the partial ZLD technology was the appropriate choice for the problems that existed at the Mayo

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Plant. However, at the time DEP chose the ZLD technology, there were only five of these systems in place worldwide for the treatment of FGD wastewater. All of these systems had been in operation for less than three years. Only one of the five systems was a partial ZLD system like the one chosen for Mayo. Given the relative newness of the application of this technology in this setting, finding experienced contractors to provide the ZLD equipment and construct the system was vitally important.

Q. **WHAT CONTRACTORS WERE SELECTED BY DEP TO EVALUATE, ENGINEER, MANAGE, AND CONSTRUCT THE ZLD SYSTEM AT MAYO?**

A. Using a multi-prime construction approach, DEP selected three primary contractors to evaluate, engineer, manage, and construct the ZLD system. The multi-prime approach eliminated the need for a general contractor but required more extensive oversite and management by DEP. The primary contractors were:

- <u>WorleyParsons</u> – supported the technical evaluation for the ZLD Island [primary components] and performed "Owner's Agent" services to represent DEP when dealing with the ZLD Island supplier and construction contractor; prepared technical bid specifications and supported DEP

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with the technical bid evaluations for balance of plant equipment.

- GEA – provided engineering and ZLD equipment.
- PCL – constructed the ZLD.

Q. WHAT IS YOUR OPINION OF THE CONTRACTORS SELECTED FOR THE PROJECT?

A. DEP's evaluation of the bidders for the construction and technical evaluation for the project appears to have been reasonable. However, regarding the selection of the contractor to engineer and provide the ZLD equipment, GEA, whom DEP selected, had less experience in providing ZLD equipment for FGD system wastewater treatment than another bidder.

[BEGIN CONFIDENTIAL]

[redacted]

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[redacted]

[END CONFIDENTIAL]

As demonstrated below, GEA's inexperience in providing ZLD equipment for FGD system wastewater treatment negatively affected the project, and a number of issues with the project arose as a result.

Q. WHAT ISSUES OCCURRED WITH THE PROJECT?

A. DEP generally described the issues that occurred in its "Project Report to the Duke Energy Corp. Transaction and Risk Committee (TRC) Mayo Zero Liquid Discharge Project February 17, 2014".[1] Below is an excerpt from this report that best summarizes the issues encountered during the project, including issues relating to GEA's performance:

[BEGIN CONFIDENTIAL]

[redacted]

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[1] The Transaction and Risk Committee is a committee of the Duke Energy Corporation Board of Directors.

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[redacted]

[END CONFIDENTIAL]

The Public Staff also reviewed numerous communications exchanged between DEP and the contractors for the project. In addition to the issues identified in the TRC report as described above, the communications revealed other issues, such as:

[BEGIN CONFIDENTIAL]

[redacted]

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[redacted]

[END CONFIDENTIAL]

DEP did provide oversight for the project, but the end result was a project that went into service a year late and was substantially over budget.

Q. DID YOUR INVESTIGATION REVEAL ANY OTHER ISSUES?

A. The Public Staff reviewed DEP's contracts with the three contractors for the ZLD system. In the GEA contract, GEA

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. DID ANY OF THE PARTIES INVOLVED ASSERT ANY CLAIMS AS A RESULT OF THE ISSUES?

A. Yes. By the end of the project, multiple claims existed between DEP and its contractors.

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[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Ultimately, the parties reached a settlement.

[BEGIN CONFIDENTIAL]

[redacted]

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[redacted]

[END CONFIDENTIAL]

Q. **WHAT WAS THE FINAL COST OF THE MAYO ZLD SYSTEM, COMPARED TO THE ORIGINAL ESTIMATE?**

A. The initial cost estimate approved by DEP management for the ZLD system was $90.6 million, net of the North Carolina Eastern Municipal Power Agency's (NCEMPA) share of the cost and including AFUDC;[2] however, the final cost upon completion was $124.9 million (again net of NCEMPA's share of the cost and

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[2] According to a response to a Public Staff data request, NCEMPA's portion of the Mayo ZLD costs are being recovered through the Joint Agency Asset Rider (JAAR). Assets in service as of July 31, 2015, were included in the acquisition costs that are subject to levelized recovery. Capital additions placed in service from August 1, 2015, are not subject to levelized recovery and are included in capital additions for rider recovery purposes. Total capital additions for the Mayo ZLD being recovered through the JAAR from August 1, 2015, through December 31, 2016, total $203,244.

including AFUDC)[3] due to the issues described above. This final cost exceeded DEP's initial, approved cost estimate by over a third.

Q. WHO SHOULD BE HELD RESPONSIBLE FOR THE ISSUES AND COST OVERRUNS THAT OCCURRED WITH THE MAYO ZLD PROJECT?

A. I believe the issues and associated cost overruns that occurred at Mayo with this project should be the responsibility of DEP and its shareholders. While the ZLD technology was the reasonable option for Mayo, DEP was fully aware that there was very limited experience installing this technology at coal-fired power plants to deal with FGD system wastewater issues, particularly at plants operating in the United States. As a result, there was an inherent level of risk with undertaking this project that would not have been present with projects utilizing established technology. DEP compounded this risk by selecting an equipment supplier that had significantly less experience constructing ZLD projects for handling FGD system wastewater than another bidder. In addition, as discussed above, DEP did not sufficiently protect itself (and customers) from unreasonable risk in its contract with GEA.

[3] Total capital cost was $141.2 million, including NCEMPA's share and without AFUDC.

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Finally, as shown above, while not as significant as the issues between DEP and GEA, issues also arose between DEP and its construction contractor, PCL that also added to the delays and associated cost overruns for the project.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission disallow inclusion of $ 34.3 million, the difference between the final project cost and DEP's estimate at the outset of the project, from rate base. I have provided my recommendation to Public Staff witness Peedin for inclusion in her testimony.

COAL ASH COST RECOVERY THROUGH THE FUEL ADJUSTMENT CLAUSE

Q. WHAT IS THE RELEVANT PROVISION IN THE FUEL ADJUSTMENT STATUTE AT ISSUE?

A. Under G.S. 62-133.2(a1)(9), "cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs."

Q. PLEASE EXPLAIN THE COMPANY'S POSITION REGARDING THE RECOVERY OF CERTAIN COAL ASH COSTS THROUGH THE FUEL ADJUSTMENT CLAUSE, G.S. 62-133.2.

A. DEP seeks to recover through the fuel adjustment clause the costs of paying Charah, LLC (Charah), to excavate coal ash from the coal ash ponds at DEP's Sutton Plant, transport it to a former clay mine in Chatham County (Brickhaven), and deposit the coal ash at Brickhaven. According to Company witnesses McGee and Kerin, the "beneficial reuse" of the Sutton coal ash at Brickhaven constitutes a "sale" of a by-product produced in the generation process, and therefore, associated gains or losses on the sale should be recoverable pursuant to G.S. 62-133.2(a1)(9).

Q. DOES THE PUBLIC STAFF AGREE THAT THE COSTS RELATING TO THE DISPOSAL OF COAL ASH AT BRICKHAVEN ARE RECOVERABLE THROUGH THE FUEL ADJUSTMENT CLAUSE?

A. No. For the reasons described in more detail below, the Public Staff believes that any such costs, to the extent they are reasonable and prudent, should be recovered in base rates and not through the fuel adjustment clause because the costs did not result from the sale of coal ash.

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Q. WHAT IS BRICKHAVEN?

A. Brickhaven is a former clay mine consisting of 333.55 acres located in Chatham County, North Carolina. By Special Warranty Deed recorded on November 13, 2014[4], Green Meadow, LLC, a wholly owned subsidiary of Charah, purchased Brickhaven from General Shale Brick, Inc. On June 5, 2015, Green Meadow, LLC, and Charah received a permit from DEQ to construct and operate Brickhaven as a "Solid Waste Management Facility, Structural Fill, Mine Reclamation"[5].

Q. WHO IS CHARAH?

A. Charah is a Kentucky-based company. According to its website, "Charah is the largest privately-held provider of coal combustion product (CCP) management for the coal-fired power generation industry in the U.S."[6] In its Limited Petition to Intervene in this case, Charah stated that it is a contractor of DEP and is engaged in the remediation of coal ash from one or more DEP facilities.

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[4] Deed Book 1770, Page 99, Chatham County Registry.

[5] The permit was issued pursuant to G.S. 130A-309.218 et. seq., relating to siting, design, construction, operation, and closure of projects that utilize coal combustion products for structural fill.

[6] http://charah.com/.

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Q. WHAT IS THE RELATIONSHIP BETWEEN CHARAH AND DEP REGARDING THE SUTTON PLANT AND BRICKHAVEN?

A. Charah is under contract with Duke Energy Business Services, LLC (DEBS), as agent for DEP to excavate coal ash from the Sutton Plant and transport and deposit the coal ash at Brickhaven.

Q. WHAT WAS THE PROCESS DEP USED TO CHOOSE CHARAH TO PERFORM THESE SERVICES?

A. In July of 2014, DEBS on behalf of Duke Energy Carolinas, LLC (DEC), and DEP issued a bidding event for the excavation, transportation, and off-site storage of the full volume of ash at four sites: Riverbend, Dan River, and Sutton in North Carolina and W.S. Lee in South Carolina.[7]

On October 3, 2014, DEBS opened a bidding event for the Phase 1 work activity (excavate, transport, and place off-site) ash at Dan River, Sutton, and W.S. Lee. Bids were solicited from three bidders, including Charah. Bids were received on October 9, 2014 (six days later). DEBS selected Charah to provide the services at the Sutton Plant.

[7] In August of 2014, DEBS requested pricing from a short list of bidders to install the infrastructure to remove, transport, and place off-site the Riverbend Plant ash stack (Riverbend Phase 1 request). Charah was awarded the project.

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Q. WAS THE PURCHASE OF THE COAL ASH AT THE PLANTS INCLUDED IN THE SCOPE OF ACTIVITIES FOR THESE BIDDING EVENTS?

A. No. Both bidding events requested fixed price proposals to excavate, transport, and store coal combustion residuals (CCRs) from the plants.

Q. PLEASE DESCRIBE THE CONTRACT BETWEEN DEBS AND CHARAH REGARDING THE REMOVAL OF COAL ASH FROM THE SUTTON PLANT.

A. DEBS (as agent for DEP and DEC) and Charah entered into Master Contract 8323 ("Master Contract") dated November 12, 2014, for the Phase 1 Excavation Work at the Riverbend and Sutton Plants. Charah is referred to as the "Seller" or "Contractor" in the Master Contract. Charah is not referred to as a "Buyer". The Master Contract defined the type and scope of work, terms and conditions, pricing, and invoicing. The Master Contract contemplated the issuance of subsequent Purchase Orders as written authorization to proceed with the scope of work identified in the Purchase Order.

Q. WHAT IS THE SCOPE OF WORK AND PRICING SCHEDULE FOR SUTTON AS DEFINED IN THE MASTER CONTRACT?

A. The Sutton Phase 1 Work Scope was set forth in Exhibit D-2 of the Master Contract. It included the installation of haul roads,

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engineering the development of a rail loading system, erosion and sedimentation control, and dewatering, ash pond excavation, transportation, unloading, and placement.

The Seller's (i.e., Charah's) Pricing Schedule was set forth as Exhibit E. The Pricing Schedule included both fixed pricing and per ton pricing. The fixed pricing was for mobilization, site preparation, erosion and sedimentation control work. The per ton pricing was for excavation, loading and transportation, unloading, development, placement, home and field office overhead, and profit.

Q. DID THE SCOPE OF WORK IN EXHIBIT D-2 OR THE PRICING SCHEDULE IN EXHIBIT E FOR SUTTON AS YOU DESCRIBE INCLUDE ANY PRICING OR DISCOUNT TO ACCOUNT FOR A SALE OF COAL ASH TO CHARAH?

A. No.

Q. WERE PURCHASE ORDERS ISSUED PURSUANT TO THE MASTER CONTRACT FOR REMOVAL OF COAL ASH FROM THE SUTTON PLANT?

A. Yes. DEBS and Charah entered into Purchase Orders authorizing Charah to transport ash from Sutton by truck to Brickhaven and then to construct and transport ash by rail to Brickhaven. Purchase Order 1107196 constituted the vast majority of the excavation,

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transportation, and disposal work for Sutton; twenty change orders were executed for this Purchase Order.

Q. DID THE SCOPE OF WORK OR PRICING SET FORTH IN THE PURCHASE ORDERS (OR CHANGE ORDERS) INCLUDE ANY PRICING OR DISCOUNT TO ACCOUNT FOR A SALE OF COAL ASH TO CHARAH?

A. No.

Q. WHAT IS THE BASIS, THEN, OF THE COMPANY'S POSITION THAT THE CONTRACTUAL ARRANGEMENT REPRESENTS A "SALE" UNDER THE FUEL CLAUSE?

A. In response to a data request, the Company summarized its position as follows:

> "…the Company's arrangement with Charah, where the Company compensated Charah for the cost of services provided by Charah net [of the] the value of the coal ash provided by the Company for the beneficial reuse constitutes a 'sale', which is supported by (1) the Commission Report describing the sale of CCRs for beneficial reuse, despite resulting in a net loss to customers; and (2) the Commission's practice of allowing the Company to recover net gains or losses from sale of CCRs through the Company's annual fuel rider."

Q. HOW DO YOU RESPOND TO THE COMPANY'S POSITION?

A. First, with respect to the arrangement between the Company and Charah, nothing in the bid documents, contracts, purchase orders, or change orders for the Sutton Plant produced in discovery assign

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any value to the coal ash to "net" against the cost of the services provided by Charah. When asked to provide all documents that show how the Company or Charah calculated the "net value" of or discount value of coal ash when setting the cost of services provided by Charah, the Company responded that it had no responsive documents. In addition, when asked how much Charah paid the Company for the Sutton coal ash, the Company responded that "there is not a defined price in the operative documents for the Sutton ash."

Certainly, DEP and Charah knew how to assign a value to coal ash in a sale: pursuant to a Master By Product Marketing, Sales, and Storage Agreement (Agreement) entered into by DEC, DEP, and Charah in December of 2013, and associated Work Orders, Charah was obligated to purchase coal ash from DEP or DEC, as applicable, at a price as set forth in the Work Orders. This Agreement formed the basis for the sale of coal ash at the Belews Creek and Marshall plants via Work Orders entered into by DEC and Charah on January 1, 2014.

The specific provisions relating to the services and pricing in the Master Contract, Purchase Orders, and change orders for Sutton all support the conclusion that the arrangement was one for Charah to provide ash disposal services to DEP, not for a sale of DEP's coal ash to Charah. Although one of the general provisions of the Master Contract stated that the services to be performed by Charah constituted payment by Charah for the ash, as noted above, DEP has admitted that there was no defined price for the ash and no documentation showing that the parties assigned any value at all to the ash. The specific provisions of both the Master Contract and Purchase Orders overwhelmingly point to a contract for services, not a sale.

Second, the findings in the "Commission Report"[8] do not support DEP's conclusion that the cost of the beneficial reuse of coal ash are recoverable through the fuel clause. The General Assembly in the legislation directed the Commission to specifically address in its report "possible revisions to the current policy on allowed incremental cost recoupment that would promote reprocessing and other technologies that allow the re-use of coal combustion residuals stored in surface impoundments for concrete and other beneficial end uses". The Commission's Report examined the statutory framework for cost recovery and concluded that current policies and practices are adequate to encourage re-use of CCRs for concrete

[8] *Report of the North Carolina Utilities Commission to the Joint Legislative Commission on Governmental Operations, the Joint Legislative Transportation Oversight Committee, and the Environmental Review Commission Regarding The Incremental Cost Incentives Related To Coal Combustion Residuals Surface Impoundments For Investor-Owned Public Utilities In North Carolina*, January 15, 2016.

and other beneficial end uses. However, as recognized by the Commission in the report, recovery through the fuel clause presupposes that there is a sale. On page 13 of the report, the Commission states, "Customers' rates are adjusted annually to include profits or losses associated with efforts to sell CCRs for beneficial re-use." On page 14 of the report, the Commission recognized that "sales of CCRs typically result in immediate net costs to ratepayers." The Commission did not conclude in its report that the costs of processing coal ash for beneficial use, without a sale, are recoverable in the fuel clause.

Finally, the Company cites the Commission's practice of allowing the Company to recover net gains or losses from the sale of CCRs through the Company's annual fuel rider in support of its position. If there is an actual sale of coal ash, cost recovery through the fuel clause may be appropriate, if the costs are reasonably and prudently incurred. Where, however, there is a contract for services not involving a sale of coal ash, costs arising from that contract should not be recoverable through the fuel clause. I conclude that the true purpose of moving coal ash from Sutton to Brickhaven is environmental remediation and the disposal of coal ash, not the sale of a byproduct.

This is the first case in which the Commission has been squarely presented with this issue. To the extent that there have been fuel cases in the past when the Public Staff has not opposed the recovery of such costs and the Commission has allowed them, it was done in the absence of knowledge that the costs were not actually sales of coal ash and should not be precedential in this case.

OVERVIEW OF COAL ASH TESTIMONY RELATED TO ENVIRONMENTAL VIOLATIONS

Q. WHAT COAL ASH TOPICS DO YOU ADDRESS IN YOUR TESTIMONY?

A. My testimony on coal ash will address the following topics: (1) the state and federal regulatory framework affecting coal ash management; (2) the litigation against DEP for alleged violations of environmental regulations on coal ash; (3) the ratemaking options for the costs of coal ash-related environmental violations and my general recommendations to the Commission; and (4) specific costs to be disallowed, regarding coal ash-related environmental violations. My coal ash disallowance recommendations are in addition to the recommendations from the Garrett and Moore consulting firm, as we address different aspects of coal ash costs.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF COAL ASH.

A. Coal ash, the main type of CCR, is one of the largest industrial waste streams in the United States.[9] In North Carolina, there are over 100 million tons of coal ash currently stored in landfills and surface impoundments owned by both DEP and DEC. CCRs are produced in the combustion process at coal-fired power plants and include by-products such as fly ash, bottom ash, coal slag, and FGD material.[10] "Coal ash" is both bottom ash and fly ash, is often treated by mixing with water in a process known as sluicing, and then diverted into surface impoundments. Surface impoundments are also known as ash basins, ponds, or lagoons. FGD material is often pre-treated in separate FGD blowdown ponds before also being sent to a CCR surface impoundment.

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[9] 117 million tons of coal ash were generated in 2015. American Coal Ash Association's Coal Combustion Product Production & Use Survey Report, available at https://www.acaa-usa.org/Portals/9/Files/PDFs/2015-Survey_Results_Table.pdf (last visited Oct. 9, 2017).

[10] Joint Factual Statement, United States of America v. Duke Energy Business Services, LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., Case No. 5:15-CR-68-H in the Unites States District Court for the Eastern District of North Carolina (May 14, 2015) at 7.

N.C. Gen. Stat. 130A-290(2b) further defines CCRs as "residuals, including fly ash, bottom ash, boiler slag, mill rejects, and flue gas desulfurization residue produced by a coal-fired generating unit destined for disposal."

For simplicity my testimony sometimes refers to "coal ash" but means all types of CCRs.

CCR STATE AND FEDERAL REGULATORY FRAMEWORK

Q. WILL YOU DISCUSS THE REGULATORY FRAMEWORK FOR COAL ASH?

A. Yes. CCR surface impoundments contain certain elements, such as arsenic, boron, cadmium, sulfate, and vanadium that can, when present in sufficient concentrations, pollute waterways, groundwater, and drinking water. CCRs were originally considered for federal regulation as part of the Resource Conservation and Recovery Act (RCRA) of 1976, but were exempted by amendment as a category of special waste, requiring further study and assessment.[11]

The Clean Air Act[12], enacted in 1970 and subsequently amended in 1990, has resulted in significant reductions in national air pollution. The result of pollutant reduction, however, meant that the pollutants were being captured by new technologies and transferred to the CCR waste stream and ultimately to CCR surface impoundments where they can eventually reach waterways and groundwater. For instance, electrostatic precipitators are an emission control technology that captures fly ash that otherwise would have been released into the air; after capture in the electrostatic

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[11] The Bevill Amenement, one of the 1980 Solid Waste Disposal Act Amendments, named after Representative Thomas Bevill, exempted fossil fuel combustion waste from regulation under Subtitle C of RCRA until further study and assessment of risk could be performed. RCRA § 3001(b)(3)(A).

[12] 42 U.S.C. § 7401 et seq. (1990).

precipitators the fly ash is collected, mixed with water, and sluiced to coal ash basins for storage.

The Environmental Protection Agency (EPA) first proposed to specifically regulate the management and disposal of CCRs in 2010 following a large spill of coal ash from a 2008 dam breach of a surface impoundment at the Tennessee Valley Authority (TVA) coal fired power plant in Kingston, Tennessee (TVA spill).[13] As part of its response to the spill, the EPA conducted a nationwide assessment of the safety of CCR surface impoundments across the United States, ranking the safety of the impoundments on the basis of dam design, safety, and integrity, including those in North Carolina.[14] In 2015, the EPA finalized the CCR rule for the comprehensive management and disposal of coal ash, under subtitle D of RCRA, as a non-hazardous solid waste.[15]

In February of 2014, between the time of the TVA spill and when the EPA finalized the CCR Rule, a spill of up to 39,000 tons of coal ash into the Dan River at DEC's Dan River Station in Eden, North Carolina occurred, creating the impetus for new regulation of coal ash at the State level; the North

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[13] Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35127 (June 21, 2010).

[14] In 2009, the EPA began a process to assess and inspect coal ash surface impoundments and rate dams for design, safety and integrity. CCR Impoundment Assessment Reports, available at https://www.epa.gov/sites/production/files/2016-06/documents/ccr_impoundmnt_asesmnt_rprts.pdf (last visited Oct. 9, 2017).

[15] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities, 80 Fed. Reg. 21301 (April 17, 2015).

Carolina Coal Ash Management Act (CAMA) became law September 20, 2014.[16] The law requires the closure of all CCR surface impoundments in the State.

The regulatory framework in place prior to the TVA spill, including the Clean Water Act and the State groundwater regulations, as well as requirements adopted after the Dan River spill, including the EPA CCR Rule and CAMA, are all relevant to the review of the Company's coal ash management and disposal in this case. A legislative and regulatory timeline is attached as **Lucas Exhibit No 1**.

Q. PLEASE SUMMARIZE THE SURFACE WATER REGULATORY REQUIREMENTS IN PLACE PRIOR TO THE TVA SPILL.

A. The Clean Water Act (CWA) was enacted in 1972 to restore the chemical, physical, and biological integrity of the Nation's waters.[17] The CWA prohibits the discharging of pollutants from point sources into a water of the United States, unless the discharge is permitted through the NPDES.[18] In 1974, the EPA promulgated the Steam Electric Power Generating Effluent Guidelines and Standards[19] that are incorporated into NPDES permits and set effluent limitations on wastewater discharges from power plants operating as utilities.

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16 Senate Bill 729, North Carolina Session Law 2014-122 (September 20, 2014).

17 33 U.S.C. § 1251 et seq. (1972).

18 13 U.S.C. §402

19 40 C.F.R. Part 423.

Q. PLEASE SUMMARIZE THE GROUNDWATER REGULATORY REQUIREMENTS IN PLACE PRIOR TO THE TVA SPILL.

A. North Carolina General Statute 143-214.1 directs the North Carolina Environmental Management Commission (EMC) to develop water quality standards applicable to the groundwaters of the State. In 1979 those groundwater quality standards were established by Title 15A, Subchapter 2L, "Groundwater Classification and Standards" of the North Carolina Administrative Code (2L rules).[20] In accordance with Section .0103 of the 2L rules, the EMC establishes the best usage of groundwater as a source of drinking water.

The groundwater quality standards are listed in Section .0202 of the 2L Rules. Other relevant sections of the 2L rules are shown in **Lucas Exhibit No. 2**. The 2L rules generally prohibit an exceedance of an established water quality standard at or beyond the compliance boundary of a permitted disposal system.[21] The compliance boundary is a certain distance from the waste boundary, depending on whether the permit was issued prior to or after December 30, 1983.[22] If the permit was issued prior to December 30, 1983, the compliance boundary is 500 feet from the waste boundary, or at the facility property line if less than 500 feet. If the permit was issued on or

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[20] 15A NCAC 02L .0101 et seq. (1979).

[21] "Compliance boundary" means a boundary around a disposal system at and beyond which groundwater quality standards may not be exceeded and only applies to facilities which have received a permit issued under the authority of G.S. 143-215.1 or G.S. 130A. 15A NCAC 02L .0102.

[22] 15 NCAC 02L .0107(a).

after December 30, 1983, the compliance boundary is 250 feet from the waste boundary, or 50 feet within the facility property line if less than 250 feet. For unpermitted systems, corrective action is necessary if there are exceedances of the standards at the waste boundary.[23]

In addition to the listed groundwater quality standards, the 2L rules also provide for the establishment of interim standards for emerging constituents for which a standard has not been established, known as interim maximum allowable concentrations (IMACs). The IMACs are published in the North Carolina Register and are considered for establishment as permanent standards in the triennial review conducted by the EPA. IMACs are enforceable groundwater standards pursuant to the 2L rules.[24]

Many of the constituents in CCRs are also naturally occurring in the soil. Per 15A NCAC 02L .0202(b)(3), where naturally occurring substances exceed the established standard, the standard is the naturally occurring concentration as determined by DEQ.25 Any background levels that are calculated to be above the 2L groundwater standards or the IMACs become the enforceable groundwater standard. The 2L groundwater standards and IMACs together are referred to as "constituents of interest."

[23] 15A NCAC 02L .0106 (c).
[24] 15A NCAC 02L .0202(c).
[25] 15A NCAC 02L .0202(b)(3).

Pursuant to 15A NCAC 02L .0106(d) and (e), when activities result in an increase of the concentration of a substance in excess of the standards at or beyond a compliance boundary then the permittee shall respond according to Paragraph (f), conduct a site assessment per Paragraph (g), and submit corrective action plans per Paragraph (h). Pursuant to the 2L rules, the site assessment reporting and corrective action plan shall be conducted in accordance with a schedule established by DEQ. The 2L rules were modified in 2016 pursuant to a provision in CAMA to align the corrective action requirements for disposal systems permitted prior to and after December 30, 1983.[26]

Q. PLEASE SUMMARIZE THE STATE DAM SAFETY REQUIREMENTS.

A. The Dam Safety Law of 1967[27] authorizes DEQ to regulate dams in the State. Under the EMC rules, each dam is given a hazard classification ranking of class A (low risk), class B (intermediate risk), or class C (high risk). Hazard classification refers to damage potential downstream and not to the condition of the dam.[28] The dam safety rules provide that dams must be inspected by DEQ every five years (Class A and B) or every two years (Class C).[29] DEQ can issue notices of deficiency for structural issues and non-structural issues.

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[26] N.C. Gen. State 143-215.1(k) as amended by S.L. 2014-122, Section 12.(a).

[27] N.C. Gen. Stat. 143-215.23 (1967).

[28] 15A NCAC, Subchapter 2K.

[29] 15A NCAC 02K .0301.

Prior to the TVA spill, CCR dams were exempt from DEQ oversight and were under the jurisdiction of the Utilities Commission; Session Law 2009-310 removed that exemption and CCR surface impoundments were placed under the jurisdiction of DEQ in 2009.[30] That 2009 law, however, also grandfathered existing CCR surface impoundments from having to submit an application or certificate to DEQ for review of the design and construction of the dam, whereas other newly permitted dams would be required to submit an application.

In 2014, the grandfathering provision in Session Law 2009-310 was amended by CAMA to give DEQ and the EMC the authority to require DEP and DEC to submit applications in connection with the continued normal operation of the facilities, and further to give authority to review safety and design of dams at CCR surface impoundment facilities.[31] CAMA further required that all CCR surface impoundments comply with more frequent and detailed inspection requirements.[32] On August 22, 2016, DEQ sent the Company a Dam Safety Order requiring repairs to several coal ash ponds as shown in **Lucas Exhibit No. 3**. The Company's response on December 14, 2016, regarding completion of the repairs is shown in **Lucas Exhibit No. 4**.

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[30] Senate Bill 1004, Session Law 2009-310, Sections 3(a) and 3(b).
[31] Senate Bill 729, Session Law 2014-122, Section 9.
[32] Id. at Section 10, amending N.C. Gen. Stat. 143-215.32(a1).

Q. HOW DOES THE EPA CCR RULE APPLY TO CCR SURFACE IMPOUNDMENTS IN NORTH CAROLINA?

A. EPA's CCR Rule establishes minimum national siting and design criteria which must be met by all CCR disposal units under the authority of subtitle D of RCRA as a non-hazardous waste. The minimum criteria consist of location restrictions, specific design and operating criteria, structural stability requirements, groundwater monitoring and corrective action, closure of the units, and post-closure care.

The CCR Rule, which became effective October 19, 2015, requires that all owners or operators of CCR surface impoundments, landfills, and lateral expansions install a system of groundwater monitoring wells, address air contamination from coal ash dust, assess the safety of coal ash impoundments, and address other potential problems.

Q. HOW DO THE EPA CCR RULE AND CAMA GENERALLY WORK TOGETHER TO REGULATE CCR SURFACE IMPOUNDMENTS IN NORTH CAROLINA?

A. The CCR Rule sets nationally applicable minimum criteria for the safe disposal of CCRs in landfills and surface impoundments and allows states to adopt more stringent standards. CAMA applies only to surface impoundments and is focused on closure methods and deadlines. Many of the requirements set forth in CAMA, including groundwater assessments, corrective action plans, drinking water well testing, identification of unpermitted discharges, dam safety, closure, and post-closure care will meet or exceed the requirements of the CCR Rule.

CAMA is more stringent than the CCR Rule in that it requires all surface impoundments to close by 2029 or sooner in accordance with a risk classification system that assigns each surface impoundment as high, intermediate, or low risk. Additionally, CAMA deemed the surface impoundments at four facilities as high priority and required closure by August 1, 2019. DEP has two generating stations designated as high priority: Sutton and Asheville.

CAMA was amended in 2015 to extend the closure deadline for the Asheville surface impoundments until August 1, 2022.[33] CAMA was additionally amended in 2016 to provide for a new deadline and criteria for the risk classification of impoundments. The 2016 CAMA legislation also deemed H.F. Lee, Cape Fear, and Weatherspoon as intermediate risk and required excavation and removal of ash from the basins at those facilities no later than August 1, 2028.[34]

Q. HOW DO THE EPA CCR RULE AND CAMA GENERALLY WORK TOGETHER WITH THE NPDES PERMITTING PROGRAM?

[33] Mountain Energy Act of 2015, S.L. 2015-110 (June 24, 2015).

[34] Drinking Water Protection/Coal Ash Cleanup Act, S.L. 2016-95 (July 14, 2016).

A. The CCR Rule and CAMA both rely on the NPDES permitting program to regulate any discharges from point sources in accordance with the CWA. CAMA requires an additional comprehensive assessment, identification, and correction of unpermitted discharges at CCR surface impoundments in the State.[35] CAMA does, however, state that these additional requirements are in addition to "any other requirements" for the identification, assessment, and corrective action to prevent unpermitted discharges.[36]

Q. HOW DO THE EPA CCR RULE AND CAMA GENERALLY WORK TOGETHER WITH THE STATE GROUNDWATER RULES?

A. The CCR Rule is designed to address releases to groundwater from CCR waste disposal units. In some cases, the constituents of interest for the CCR Rule and the state groundwater rules are different or have different standards. The CCR Rule bases its standards on national maximum contaminant levels (MCLs) established by the EPA for drinking water quality pursuant to the Safe Drinking Water Act.[37] The 2L rules are developed taking into account the MCL rules, but may be more stringent and may consider other constituents of interest. A further difference is that the CCR Rule requires monitoring and compliance at the waste boundary, whereas the state groundwater rules and CAMA require compliance at the

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[35] N.C. Gen. Stat. 130A-309.212

[36] N.C. Gen. Stat. 130A-309.212(a),(b),(c).

[37] 42 U.S.C. § 300 (1974).

compliance boundary for permitted systems. The CCR Rule is also self-implementing, meaning the Company is required to comply and citizens can bring citizen action suits, but EPA and DEQ have no formal role in implementation nor can they enforce the requirements.[38]

Pursuant to the CCR Rule, Groundwater Protection Monitoring must be performed. The Appendix III parameters, which include boron, calcium, chloride, fluoride, pH, sulfate, and total dissolved solids (TDS), must be monitored semi-annually. If it is determined that there has been a statistically significant increase (SSI) over the established background level for any of the Appendix III parameters, then Groundwater Assessment Monitoring must begin within 90 days. The Assessment Monitoring shall include the Appendix III and Appendix IV substances and establish a groundwater protection standard (GWPS) for each Appendix IV constituent. The Appendix IV constituents include antimony, arsenic, barium, beryllium, cadmium, chromium, cobalt, fluoride, lead, lithium, mercury, molybdenum, selenium, thallium, and Radium 266-228 combined. The GWPS is to be the maximum contaminant level or background level, whichever is higher.

If any Appendix IV constituents are determined to have an SSI in exceedance of the GWPS, then the nature and extent of the release must

[38] DEQ can enforce CCR Rule requirements to the extent the EMC adopts those requirements into state regulations.

be characterized, additional monitoring wells must be installed, and assessment of corrective action must be started.

CAMA generally follows the requirements of the structure of the 2L rules; it requires a site assessment, submittal of corrective action plans, and post-closure care. CAMA also cites back to the 2L rules and requires the submittal of a groundwater protective action plan for the restoration of groundwater quality in conformance with the 2L rules.39

As enacted in CAMA, G.S. 130A-309.211(a) and (b) requires groundwater assessment and corrective action at CCR surface impoundments as follows:

1. Submit a proposed Groundwater Assessment Plan to DEQ for review and approval;
2. Implement the Groundwater Assessment Plan and submit a Groundwater Assessment Report that describes "all exceedances of groundwater quality standards associated with the impoundment";
3. Submit a proposed Groundwater Correction Action Plan to DEQ for review and approval; and

[39] N.C. Gen. Stat. 130A-309.211(b).

4. Implement the Groundwater Correction Plan to restore the groundwater quality in conformance with the requirements of the 2L rules.

This process parallels the requirements detailed in 15A NCAC 02L .0106 Paragraphs (f), (g), and (h); however, CAMA set specific deadlines which otherwise would have been at the discretion of the DEQ Secretary.

Q. WHAT IS THE CURRENT COMPLIANCE STATUS FOR DEP CCR SURFACE IMPOUNDMENTS WITH STATE STANDARDS FOR SURFACE WATER RULES?

A. The EPA has authorized DEQ, Division of Water Resources, to implement the NPDES permitting program.[40] All of North Carolina's 14 coal-fired power plants have NPDES permits. The CWA specifies that NPDES permits may not be issued for a term of more than five years. If a permittee applies for a permit renewal prior to the expiration of the permit, the permit may be administratively continued until it is reissued.

Currently, DEP has six NPDES permits that are under consideration for renewal. The NPDES permit for the Sutton plant was renewed on September 29, 2017.

[40] N.C. Gen. Stat. § 143B-282(a)(1)(a).

As of this date, DEQ is still developing its policy on seeps from coal ash impoundments and will issue permits after its decision. A summary of NPDES permit violations is shown in **Lucas Exhibit No. 5**.

Q. WHAT IS THE STATUS OF COMPLIANCE WITH STATE GROUNDWATER STANDARDS FOR DEP SURFACE IMPOUNDMENTS?

A. The Company has provided the Public Staff with a timeline for establishing DEQ-approved provisional background concentrations for constituents of interest at all the CCR surface impoundment sites pursuant to the 2L standards. The background concentrations, known as provisional background threshold values (PBTVs), are necessary to determine whether exceedances of groundwater quality standards were caused by the migration of constituents from CCR impoundments. The Company expects to reach consensus with DEQ on the provisional background concentrations for constituents of interest at all sites by the end of November 2017.

DEP has also stated that the monitoring data being collected in compliance with the CCR Rule will not be available until January of 2018.

Q. HAS DEP CONDUCTED ENVIRONMENTAL AUDITS OF GROUNDWATER AROUND ITS ASH BASINS?

A. Yes. The federal criminal case brought against DEP, DEC, and Duke Energy Business Services (DEBS) resulted in a requirement that a court appointed monitor (CAM) oversee the Company's compliance with the conditions of probation.[41] One of the conditions is environmental audits for each of DEP and DEC's facilities with CCR surface impoundments.

The Final Audit Reports conducted by Advanced GeoServices Corp. and The Elm Consulting Group International LLC have identified numerous exceedances of the groundwater quality standards at DEP's generating stations. Each of the Final Audit Reports, available as of October 4, 2017, are posted online by Company in accordance with the terms of the federal plea agreements.

The Audit Report findings of exceedances at or beyond the compliance boundary are summarized in **Lucas Exhibit No. 6**.

Q. DO YOU BELIEVE THAT GROUNDWATER EXCEEDANCES OTHER THAN THOSE LISTED IN THE FINAL AUDIT REPORT HAVE OCCURRED?

A. Yes. The Public Staff has compiled a table summarizing the groundwater monitoring data that exceed the 2L standards or IMACs at each of DEP's generating stations, shown in **Lucas Exhibit No. 7**. The exceedances are individual laboratory analysis results for specific parameters that are above the acceptable regulatory concentration levels. For example, 10 sample events reporting concentration levels above the 2L standards or IMACs

[41] See https://www.duke-energy.com/our-company/environment/compliance-and-reporting/environmental-compliance-plans for copies of reports from the CAM, Duke Energy's compliance officer, and the environmental audits.

would result in 10 exceedances. Those exceedances may be from the same monitoring wells over months, or even years, or from multiple monitoring wells.

For the purposes of identifying the minimum number of groundwater quality violations, the Public Staff believes that utilizing the PBTVs, which have been proposed by DEP and are under review by DEQ, is the most conservative approach for quantifying the effect of CCRs on groundwater. However, given the pending and provisional nature of these values, the Public Staff has not attempted to draw detailed conclusions prior to DEQ's determination of whether all these exceedances are due to naturally occurring background concentrations or attributable to the migration of DEP's CCR constituents. Instead, based on the available data, I believe it is fair to make a broad conclusion at this time that at least some of the exceedances are due to migration of CCR constituents. Exceedances of 2L standards and IMACs (or exceedances of PBTVs if they are higher than 2L standards or IMACs) at or beyond the compliance boundary, represent a probable failure to meet environmental standards – a violation – that would need to be corrected to achieve compliance with 15A NCAC 02L .0106.

OVERVIEW OF LITIGATION OF ENVIRONMENTAL VIOLATIONS AT DEP CCR FACILITIES

Q. HAVE LEGAL ACTIONS BEEN FILED AGAINST DEP FOR UNLAWFUL MANAGEMENT OF COAL ASH AND POLLUTION FROM COAL ASH?

A. Yes. Governmental agencies and environmental groups have sued DEP in state court with regard to the handling and impacts of coal ash. It appears the state enforcement actions filed by DEQ were prompted by "notice of intent to sue" letters from environmental groups represented by the Southern Environmental Law Center (SELC). DEQ also brought an administrative penalty proceeding against DEP in connection with the Sutton plant, environmental groups brought several federal citizen action suits against DEP, and the federal government brought a criminal case against DEP for violations at several plants. **Lucas Exhibit No. 8** is a chart showing the legal actions.

Q. PLEASE SUMMARIZE THE STATE COURT LITIGATION ON COAL ASH.

A. On March 22, 2013, and August 16, 2013, DEQ brought suits in Wake County Superior Court for violations at the Asheville, Cape Fear, H.F. Lee, Mayo, Roxboro, Sutton, and Weatherspoon generating stations. Environmental groups represented by SELC intervened.

DEQ sued DEP in Wake County Superior Court, Nos. 13-CVS-4061 and 13-CVS-11032. DEQ alleged unlawful discharges from coal ash basins to surface waters of the State in violation of G.S. 143-215.1(a)(1) and (a)(6), non-compliance with NPDES permits, and known and potential groundwater exceedances in violation of 2L rules. For example, the DEQ complaint on the Asheville plant stated in part:

> 80. On March 11, 2013, DWQ staff inspected the Asheville Steam Electric Plant and observed several seeps from the facility discharging into surface waters adjacent and flowing to the French Broad River. Seeps identified at the site, included engineered discharges from the toe-drains of the 1964 and 1982 Coal Ash Ponds, discharges from the Asheville Steam Electric Plant property west and southwest of the coal ash ponds, including areas west of Interstate Highway 26, up to the banks of the French Broad River. These locations are different from the outfalls or stormwater outlets described in the Asheville Steam Electric Plant NPDES Permit.
>
> . . . .
>
> 89. Defendant's exceedances of the groundwater standards for Iron, Manganese, Boron, Thallium, and TDS at the compliance boundary of the Asheville Steam Electric Plant Ash Pond are violations of the groundwater standards as prohibited by I5A NCAC 2L.0103(d).

<u>Asheville and Sutton dispositions</u>: On June 1, 2016, with support from all parties, the court granted partial summary judgment and dismissed the claims against the Asheville and Sutton plants, as well as two DEC plants, on the grounds that

> the issues alleged in the various Complaints with regard to unpermitted discharges, and with regard to violations of NPDES permits and groundwater standards at these facilities will be remedied by compliance with the provisions of this Order and the provisions of CAMA applicable to the four plants included in this Order.

Because the Asheville and Sutton plants are high priority sites under CAMA, the statute requires that DEP dewater, excavate, and remove the coal ash as part of its closure plan. CAMA requirements thus fulfilled the objectives sought by the demand for injunctive relief, so the court never had to rule on whether the alleged environmental violations were proven.

Cape Fear, H.F. Lee, and Weatherspoon dispositions: On April 4, 2016, with support from DEP and the environmental intervenors but not from DEQ, the court granted partial summary judgment and dismissed the claims against the Cape Fear, H.F. Lee, and Weatherspoon plants on the grounds that DEP's plan to dewater, excavate, and remove the ash from the basins at these plants, in conjunction with the requirements of CAMA, would satisfy the relief requested. While these plants were not designated as high priority in the 2014 CAMA legislation, DEP's decision to close them to the standards required of high priority plants effectively settled the litigation. The 2016 CAMA legislation subsequently adopted the requirement for excavation and removal of coal ash from these plants, in effect legislating what was already settled in the lawsuit. The court thus never had to rule on whether environmental violations were proven.

Mayo and Roxboro dispositions: SELC's state court claims for injunctive relief regarding coal ash-related environmental violations at the Mayo and Roxboro plants remain in litigation.

Q. PLEASE SUMMARIZE SELC'S FEDERAL COURT ACTIONS ON COAL ASH.

A. On September 12, 2013, September 3, 2014, June 13, 2016, May 16, 2017, and June 20, 2017, SELC filed suits in federal courts for violations at the Cape Fear, H.F. Lee, Mayo, Roxboro, and Sutton plants. SELC filed this series of "citizen action" complaints, alleging unlawful discharges and other CWA, on behalf of various environmental groups.

The 2013 action regarding Sutton violations concluded with a settlement in which DEP agreed to pay $1 million, and an additional matching amount up to $250,000, for funds dedicated to the restoration and preservation of the Cape Fear River and Sutton Lake. The settlement came after three years of litigation and a court ruling that dismissed groundwater claims on jurisdictional grounds, but allowed claims for unlawful discharges of coal ash wastewater to proceed.

The 2014 federal court actions regarding Cape Fear and H.F. Lee were voluntarily dismissed by SELC in light of the relief granted in the state court case against those plants.

The 2016 and 2017 federal court actions regarding Mayo and Roxboro remain in litigation. SELC alleges that DEP's cap-in-place closure plan for Mayo will violate the CCR Rule because it will leave as much as 70 feet of coal ash submerged in groundwater, causing ongoing contamination. The complaint includes allegations that

> 37. The leaking, unlined coal ash lagoon at Mayo has contaminated the groundwater outside the lagoon with numerous coal ash pollutants, including antimony, arsenic, barium, boron, chromium, cobalt, iron, manganese, pH, thallium, total dissolved solids, and vanadium. For example, chromium has been detected at 301% above the state groundwater standard, and manganese – associated with nervous system and muscle problems – at 2,780% above the standard.
>
> 38. Duke Energy's coal ash in the groundwater at Mayo has polluted both Crutchfield Branch and Mayo Lake, as the polluted groundwater moves from the coal ash submerged in groundwater into Crutchfield Branch and Mayo Lake. Sampling in Crutchfield Branch and Mayo Lake has revealed elevated levels of many coal ash pollutants, including boron, cobalt, copper, thallium, vanadium, and selenium, among others.
>
> 39. As long as the coal ash remains in the groundwater and in unlined storage, it will continue to contaminate groundwater and adjacent surface waters.

With regard to Roxboro, SELC alleges unlawful direct discharges of coal ash into a bay of Hyco Lake and Sargents River, and alleges unlawful pollution of waters of the United States via hydrologic conveyance of coal ash-contaminated groundwater to those waters.

Because CAMA requires dewatering, excavation, and removal of coal ash from the basins at Asheville, Sutton, Cape Fear, and H.F. Lee, the plaintiffs' objectives were generally met by legislation, enabling dismissal of the lawsuits for those plants. However, Mayo and Roxboro remain eligible to be classified as low risk sites under CAMA, where cap-in-place may be a lawful remedy. Cap-in-place closure of ash basins is not satisfactory to the plaintiffs, and thus the lawsuits involving Mayo and Roxboro are ongoing.

Q. PLEASE SUMMARIZE THE DEQ PENALTY PROCEEDING AGAINST DEP FOR GROUNDWATER EXCEEDANCES AT SUTTON.

A. DEQ assessed a $25.1 million penalty for violations of 2L groundwater standards at the Sutton plant, independent of DEQ's state court action for injunctive relief that also involved Sutton. DEQ findings for the penalty included the following:

> P. The Division received groundwater monitoring reports from Duke Energy beginning in 1995. Monitoring reports confirm that violations of the Groundwater Quality Standards have occurred at or beyond the compliance boundary at this facility.
>
> Q. Groundwater monitoring wells MW-4 and MW-5 represent background ambient conditions.
>
> R. The violations of Groundwater Quality Standards for Arsenic occurred in monitor well MW-21 C, located at or beyond the Compliance Boundary. Concentrations of Arsenic were determined to be below detection levels in background wells. The concentrations of Arsenic in monitoring well(s) exceeded the Groundwater Quality Standards for the time period from October 2, 2013 through October 2, 2014, representing 365 days of continuous violation.
>
> S. The violations of Groundwater Quality Standards for Boron occurred in monitor wells MW-12, MW-19, MW-21C, MW-22C, MW-23B, MW-23C, MW-24B, MW-24C, and MW-31C located at or beyond the compliance boundary. Concentrations of Boron were determined to be below detection levels in background wells. The concentrations of Boron in monitoring well(s) exceeded the Groundwater Quality Standards for the time period from October 6, 2009 through October 2, 2014, representing 1,822 days of continuous violation.

T. The violations of Groundwater Quality Standards for Iron occurred in monitor wells MW-21 C, MW-24C, and MW-31 C located at or beyond the compliance boundary. The concentrations of Iron in monitoring well(s) indicate a statistically significant difference when compared to the concentrations of Iron in the background wells, indicating an exceedance of the Groundwater Quality Standards for the time period from October 2, 2012 through October 2, 2014, representing 730 days of continuous violation.

U. The violations of Groundwater Quality Standards for Manganese occurred in monitor wells MW-19, MW-21C, MW-22C, MW-23C, MW-24C, and MW-31C located at or beyond the compliance boundary. The concentrations of Manganese in monitoring well(s) indicate a statistically significant difference when compared to the concentrations of Manganese in the background wells, indicating an exceedance of the Groundwater Quality Standards for the time period from October 2, 2012 through October 2, 2014, representing 730 days of continuous violation.

V. The violations of Groundwater Quality Standards for Selenium occurred in monitor well MW-27B, located at or beyond the compliance boundary. Concentrations of Selenium were determined to be below detection levels in background wells. The concentrations of Selenium in monitoring well (s) exceeded the Groundwater Quality Standards for the time period from October 2, 2012 through October 1, 2014, representing 729 days of continuous violation.

W. The violations of Groundwater Quality Standards for Thallium occurred in monitor wells MW-19 and MW-24B located at or beyond the compliance boundary. Concentrations of Thallium were determined to be below detection levels in background wells. The concentrations of Thallium in monitoring well(s) exceeded the Groundwater Quality Standards for the time period from March 9, 2010 through October 2, 2014, representing 1,668 days of continuous violation.X. The violations of Groundwater Quality Standards for Total Dissolved Solids (TDS) occurred in monitor well MW-24C located at or beyond the compliance boundary. Concentrations of TDS were determined to be below detection levels in background wells. The concentrations of TDS in monitoring well(s) exceeded the Groundwater Quality Standards for the time period from

> October 3, 2012 through October 1, 2014, representing 728 days of continuous violation.

On March 10, 2015, DEP contested the findings in a petition filed at the Office of Administrative Hearings (OAH), No. 15-EHR-02581. On September 29, 2015, the DEP petition for contested case was dismissed pursuant to a settlement agreement with DEQ. In the settlement, Duke Energy admitted no wrongdoing, agreed to pay $7 million to DEQ, and agreed to accelerated remediation of coal ash at the Sutton, Belews Creek, Asheville, and H.F. Lee plants. The settlement did acknowledge "offsite groundwater impacts" at these facilities. The remediation work for Sutton includes extraction wells to pump groundwater in an effort to slow offsite migration from the ash basins.

The Sutton settlement between DEQ and Duke Energy contained provisions to end DEQ environmental litigation on groundwater exceedances at all Duke Energy facilities, not just the Sutton penalty assessment. The agreement noted that DEQ had a policy of deferring enforcement and monetary penalties if Duke Energy would work cooperatively with the agency when there was non-compliance:

1. The 2011 Policy for Compliance Evaluations is a current DEQ policy that was in effect at the time DEQ issued the Sutton NOV, the Asheville NOV and Penalty Assessment against Duke Energy;

2. The 2011 Policy for Compliance Evaluations applies to each of the Duke Energy Sites listed above;

3. The 2011 Policy for Compliance Evaluations states that as "long as the permittee is cooperative with the Division in taking the necessary steps to bring the facility into compliance, a notice of violation may not be necessary."

4. During the discovery process internal e-mails and testimony by former DENR management demonstrate that, although not expressly stated in the 2011 Policy for Compliance Evaluations, the intent at the time of the 2011 Policy for Compliance Evaluations was that corrective action would precede any enforcement and would be in lieu of monetary penalties.

DEQ agreed to dismiss its groundwater exceedance claims against all Duke Energy coal plants in North Carolina, and agreed not to file any notices, claims, enforcement actions, or penalties against Duke Energy for groundwater conditions, past or future, as long as Duke Energy was complying with CAMA.

On October 13, 2015, SELC petitioned for judicial review of the penalty settlement in No. 15-CVS-13760 filed in Wake County Superior Court. The petition case was settled by the parties through modification of the original order of dismissal at OAH. The modification resulted in a February 23, 2016, amended order of dismissal that deleted reference to resolution of groundwater claims involving plants other than Sutton. However, the DEQ settlement with Duke Energy remained unchanged, thereby effectively ending DEQ groundwater claims at all Duke Energy plants. The intent of the amended order was to allow intervenor parties in the state court enforcement lawsuits to maintain their claims.

Q. PLEASE SUMMARIZE THE DEP AGREEMENT IN SOUTH CAROLINA REGARDING THE ROBINSON PLANT.

A. On July 17, 2015, DEP entered an agreement with the South Carolina Department of Health and Environmental Control (DHEC) for removal of stored coal ash at the Robinson plant. DEP entered Consent Agreement No. 15-23-HW without DHEC having filed any formal enforcement action. The agreement provides that DEP will excavate and remove coal ash stored in a basin and in a non-basin area of the Robinson plant. The work includes assessment, and a Closure Plan and Remedial Plan. DEP is to reimburse DHEC for the agency's costs incurred in oversight of the agreement. The stated goal of the agreement is protection of human health and the environment.

Q. PLEASE SUMMARIZE THE FEDERAL CRIMINAL CASE BROUGHT IN THE WAKE OF THE DAN RIVER SPILL.

A. On February 20, 2015, criminal charges were brought by the U.S. Department of Justice and U.S. Attorney offices for violations of the Clean Water Act at the Asheville, Cape Fear, and H.F. Lee plants. While the major ash spill at DEC's Dan River plant was the impetus for this prosecution, it also addressed violations at DEP plants.

For the H.F. Lee plant, DEP pled guilty to a misdemeanor involving unpermitted discharge from an active coal ash basin through seeps into the Neuse River via drainage ditches ("engineered seeps"). According to the

Joint Factual Statement appended to the plea agreement, DEQ sampling in 2013 from one of the ditches showed exceedances of state water quality standards for chloride, arsenic, boron, barium, iron, and manganese.

For the Cape Fear plant, DEP pled guilty to two misdemeanors for failure to maintain risers at two ash basins, resulting in leakage of coal ash wastewater from the impoundments.

For the Asheville plant, DEP pled guilty to a misdemeanor involving unpermitted discharges from engineered seeps through an ash basin toe drain into the French Broad River.

The federal criminal charges were resolved by a plea agreement from DEP, DEC, and DEBS in Case Nos. 5:15-CR-68-H, 5:15-CR-62-H, and 5:15-CR-67-H. The agreement provides for DEP to pay specified fines, and to pay other costs generally for remedial and oversight purposes, which DEP was not allowed to recover through rates. The required DEP payments total $29.9 million before accounting for restitution costs and funding of the Environmental Compliance Plans, Court Appointed Monitor, and environmental audits.

Q. WHAT DO YOU CONCLUDE FROM THIS HISTORY OF LEGAL ACTIONS ALLEGING COAL ASH-RELATED ENVIRONMENTAL VIOLATIONS BY DEP?

A. The federal criminal prosecution established certain engineered seeps as environmental violations. In my opinion, DEP's agreement to pay up to $1.25 million in settlement of the SELC federal citizen action suit on Sutton, and another $7 million to DEQ for groundwater violations at Sutton, are persuasive evidence of environmental violations notwithstanding DEP's denial of liability. The DHEC consent agreement was in lieu of enforcement action, so there is no evidence proving or disproving environmental violations. Likewise, with other claims of coal ash-related environmental litigation, the matters were either resolved without any finding on environmental violations, or are still pending a decision (actions regarding the Mayo and Roxboro plants). The current DEQ approach of working with DEP to remediate coal ash issues through an effort to achieve compliance with CAMA means (a) further adjudication of environmental violations may be avoided for most coal ash sites, and (b) there nonetheless may be data showing violations such as well monitoring reports and related assessments. In summary, the federal criminal case shows actual coal ash-related environmental violations at three DEP coal plants, the two Sutton settlements indicate probable environmental violations, and the other environmental litigation leaves open the possibility of additional environmental violations being shown either in court or through data reported to DEQ.

COSTS OF CCR-RELATED ENVIRONMENTAL VIOLATIONS AND RATEMAKING OPTIONS FOR THOSE COSTS

Q. FOR COAL ASH MANAGEMENT, HAS DUKE ENERGY INCURRED COSTS RELATED TO NON-COMPLIANCE WITH ENVIRONMENTAL REGULATIONS?

A. Yes. The most publicized costs are the clean-up, criminal charges, and fines for the Dan River spill. In addition, there have been unpermitted discharges, exceedances of groundwater water quality standards, and other violations of environmental regulations at coal ash disposal sites of both DEP and DEC. There will be substantial costs to remedy coal ash-related environmental violations and risks of violations, whether the remedies are required by citizen action lawsuits, regulatory enforcement, or laws like the CCR Rule and CAMA that were adopted in response to environmental violations. As noted above, some environmental violations have been established, and others are likely to be established in the future through ongoing monitoring and assessments of ash basins. In some cases, there are known costs resulting from environmental violations, and some of those have been required by federal plea agreement to be excluded by DEP from its rate request. Some costs related to environmental violations are included in the rate request. Other costs associated with actual and potential environmental violations are not known at this time. A major issue in this rate case is determining the appropriate regulatory treatment of costs resulting from non-compliance with environmental regulations.

Q. WHAT REGULATORY OPTIONS HAS THE PUBLIC STAFF CONSIDERED WITH RESPECT TO COSTS OF COAL ASH-RELATED ENVIRONMENTAL VIOLATIONS?

A. The option advocated by DEP is to treat its coal ash-related costs as required for compliance with CAMA and the CCR Rule, and therefore as reasonable to recover in rates. They have excluded from their rate request the costs of fines, penalties, and certain other costs specified in their federal plea agreement.[42] Under DEP's view, the costs to remedy environmental violations and alleged violations are no different from the costs to comply with CAMA (with a few exceptions such as fines and penalties), so the Company would have reasonably expended those amounts even without environmental violations.

An alternative option is to conclude that CAMA is a direct consequence of environmental violations caused by the imprudent or negligent coal ash management of Duke Energy, and therefore DEP (and DEC) shareholders should bear responsibility for the full costs to comply with CAMA.

[42] Duke Energy has also stated that if it prevails in its lawsuit against its insurers for policy coverage of coal ash-related costs, it will flow those monies through to the benefit of ratepayers.

A third option is to assign cost responsibility to DEP shareholders for the costs to defend against environmental violations, and the costs to remedy those environmental violations, except to the extent that CAMA has imposed new requirements that increased the cost of remediation. A hypothetical example would be the need to remedy groundwater violations by excavating an ash basin and moving the ash to a lined landfill, (costs on shareholders), but where CAMA imposed a tight deadline that required transport to an offsite landfill, the costs would be significantly higher than if an onsite lined landfill could have been used (incremental additional costs on ratepayers). The Public Staff prefers this option in principle; however, there are complications with using it to assign cost responsibility.

Q. WHAT ARE THE COMPLICATING FACTORS IN THE ANALYSIS OF COST RESPONSIBILITY?

A. The Public Staff believes the issue of cost responsibility for environmental violations is complex, and needs to account for the following factors.

1. There is no indication of legislative intent to relieve DEP of cost responsibility for environmental violations where those costs are for the same activities needed to comply with CAMA. It is the opinion of the Public Staff that the General Assembly did not intend CAMA to be a shield to protect DEP from responsibility for environmental violations. CAMA was enacted

in addition to, not as a replacement for, existing environmental laws and regulations such as G.S. 143-215.1, NPDES permit requirements, and 15A NCAC 2L.

2. While some environmental violations are clearly due to DEP negligence or mismanagement, there are other actual and potential environmental violations that are not easily characterized as either plainly imprudent or plainly reasonable on DEP's part. For instance, if there is no convincing evidence of imprudence with regard to decisions on storage of coal ash in unlined impoundments at the time the impoundments were constructed, should DEP nonetheless be held responsible for the costs when coal ash contaminants leaked from those impoundments into surface waters and groundwater outside the compliance boundaries? The duty to avoid contamination of waters of the State and of groundwater outside the compliance boundaries is effectively a strict liability – old impoundments are not grandfathered, and no showing of imprudence is required to establish a violation of 2L rules. That is, DEP had a duty to comply without regard to whether they followed accepted industry practices. Counsel advises me that the Commission has the legal authority to determine that it is not reasonable to impose the cost of DEP non-compliance with environmental regulations on ratepayers. Accepted industry practices are not

necessarily reasonable if those practices result in environmental violations. On the other hand, prudence disallowances have historically been premised on some degree of utility fault attributable to specific decisions that constitute mismanagement.

3. The calculation of some of the costs for coal ash-related environmental violations could be extremely complex and somewhat speculative. For example, most violations could arguably have been avoided by taking a different approach to ash management in earlier years (such as lining the ash basins with impervious materials or creating dry stack lined landfills), but those different approaches would have had a cost to DEP and therefore to its ratepayers. The costs of approaches in earlier years to avoid environmental violations would arguably have to be subtracted from the costs to remedy environmental violations, on a present value basis, to determine the net avoidable cost of environmental violations. Such an exercise would require a lot of estimations and assumptions over a long period of time, leaving doubts about accuracy.

Q. WHAT IS YOUR RECOMMENDATION IN LIGHT OF THOSE DIFFERENT REGULATORY OPTIONS AND COMPLICATING FACTORS?

A. The Public Staff is supportive of the principle that costs to resolve and remediate environmental violations should be disallowed from recovery in rates, except to the extent that CAMA or the CCR Rule increased such costs. However, in light of the complicating factors listed above, we recommend a ratemaking approach that balances the equities between ratepayers and shareholders. Certain costs are so clearly due to Company failure to comply with environmental regulations that none of those costs should be assigned to ratepayers. However, for most of the coal ash-related costs in the DEP rate request there is some degree of DEP culpability for costs, due to non-compliance with environmental regulations, but it may fall short of imprudence. In this situation, an equitable sharing of those costs is reasonable and appropriate, as discussed by Public Staff witness Maness.

In particular, the Public Staff recommends that the following expenditures be excluded from rate recovery: (1) DEP litigation costs and settlement payments in cases where there are environmental violations; (2) costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations; and (3) costs required to be excluded under the probation conditions of the federal plea agreement. These exclusions are in addition to the recommended disallowances from Garrett and Moore to the extent there is no double disallowance for the same item. In addition, the Public Staff recommends that the Commission accept the imprudence adjustments of Garrett and

Moore, and effectuate an equitable sharing of the remaining allowed costs of coal ash management through the deferral and amortization approach recommended by Public Staff witness Maness.

Q. PLEASE EXPLAIN THE FIRST CATEGORY OF EXPENSES WHICH YOU RECOMMEND BE EXCLUDED FROM RATES.

A. The first category is litigation costs where there are environmental violations. It is routine in ratemaking to disallow from the utility's revenue requirement any costs of fines and penalties. Legal counsel informs me that North Carolina law also supports exclusion of other expenses related to utility violations of law. The North Carolina Supreme Court ruled that legal expenses incurred by a water utility in defense of a penalty proceeding must be excluded from rate recovery as a matter of law[43]:

> Glendale [Glendale Water, Inc., a regulated utility] was penalized for violating serious administrative regulations, including its failure to notify its customers of contaminants in the water. It would be improper to require the very class of people the DHS sought to protect in assessing the penalty against Glendale to indirectly pay for the penalty through the inclusion of related legal fees into Glendale's operating expenses. Furthermore, since these legal fees could have been avoided had Glendale initially carried out its responsibility of providing adequate water service to its subdivisions, this expense cannot properly be considered reasonable or necessary.

The principle set forth in this ruling is applicable to the present rate case for litigation expenses related to the failure of DEP to comply with

[43] State ex rel. Utilities Comm. v. Public Staff, 317 N.C. 26 (1986).

environmental laws and regulations. In particular, I recommend disallowance of all legal expenses incurred by DEP in the course of defending and resolving the federal criminal charges. In addition, I recommend disallowance of any other costs related to the defense of that case, including costs for third party assistance (expert witnesses, consultants, and other contractors) and for internal labor that should be assigned or allocated to defense of that case. Such costs are properly excluded from rate recovery under both the holding of the Glendale Water case and under the ratemaking principle that it is not reasonable for consumers to bear the costs of utility misfeasance or malfeasance. Misfeasance is established in the federal criminal case by DEP's guilty pleas and supported by the Joint Factual Statement appended to the Plea Agreement.

DEP also settled two civil cases alleging environmental violations. In the first case, DEP agreed to make a $1 million payment, and another payment of up to $250,000, to a fund for restoration of the Cape Fear River and Sutton Lake to settle alleged Clean Water Act violations. In the second case, Duke Energy agreed to make a $7 million payment (DEP is responsible for $6 million of the total) to DEQ to settle a penalty assessment for groundwater exceedances at the Sutton plant. While DEP did not admit to environmental violations, the Company's settlement payments, legal fees and other costs to defend those lawsuits should be excluded from rate recovery. The reasons for this recommendation are: (a) the complaints and monitoring well data indicate substantial evidence of major groundwater contamination from the Sutton ash basins, with impacts on community drinking water supplies, and (b) if DEP did not commit the violations, it should not have made those settlement payments.

The same principle of disallowance for litigation costs should apply in all other past and future lawsuits to the extent that either: (a) there is a final order finding DEP liable for environmental violations; (b) DEP agrees to make a payment in settlement; or (c) DEQ determines groundwater exceedances at locations involved in past litigation, thereby substantiating the allegations.

Q. HAVE YOU CALCULATED THE AMOUNT OF LITIGATION AND SETTLEMENT COSTS THAT SHOULD BE DISALLOWED?

A. Yes, to the extent known at this time. DEP states that it has excluded the $1.25 million and $7 million ($6 million share for DEP) settlement payments related to Sutton; therefore, no adjustment is necessary for these costs. In addition, Duke Energy incurred approximately $88,000 in litigation costs in the test year and these costs should be excluded from rates for the same reasons I recommend exclusion of the settlement payments. This amount is significantly less than the total spent on litigation costs because other expensed legal fees occurred outside of the test year.

Some litigation costs will not be known until future developments show if there have been more environmental violations that we cannot ascertain presently. The Public Staff will make recommendations on the regulatory treatment of such costs in future cases after the full facts are known.

Q. PLEASE EXPLAIN THE SECOND CATEGORY OF EXPENSES WHICH YOU RECOMMEND BE DISALLOWED.

A. The second category is costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations. An example would be settlements where DEP agreed to take remedial measures, such as extraction wells at Sutton, such that the settlement cost more than it would have been necessary to pay for CAMA compliance without violations. Another example would be rulings in lawsuits alleging environmental violations, where the rulings result in remedial actions costing more than the risk classifications warrant. The Mayo and Roxboro plants are eligible for cap-in-place closure, but the pending federal citizen action lawsuits or state court claims could require a costlier cleanup if groundwater violations are established. Such settlements could be agreements that resolve lawsuits alleging environmental violations, or they could be more informal resolutions with regulatory authorities. My recommendation here is not for shareholders to bear all the remedial costs, but rather the amount of remedial costs that are above the lowest reasonable costs to comply with CAMA in the absence of environmental violations.

The reason for shareholders to be assigned all of the incremental environmental cleanup **costs** above the CAMA compliance costs is that the culpability for such costs rests entirely with the Company. DEP had a legal duty to comply with dam safety rules, NPDES permit requirements, and 2L groundwater standards. Where DEP's failure to comply with that duty resulted in avoidable costs, above CAMA compliance costs, it would be unreasonable to charge those avoidable costs to ratepayers.

Q. HAVE YOU CALCULATED THE EXTENT TO WHICH COSTS TO REMEDY ENVIRONMENTAL VIOLATIONS EXCEED CAMA COMPLIANCE COSTS?

A. Yes, to a limited degree. I recommend that expenditures for groundwater extraction and treatment not be included in cost of service. The process of extracting contaminated groundwater and treating it before it can be disposed is the direct result of DEP's mismanagement of coal ash. These costs should not be passed on to DEP's customers. For calendar year 2016, these costs were $1,053,829, and for the update period of January 1, 2017, through August 31, 2017, these costs amounted to $5,639,561, for a recommended total NC retail cost of service adjustment of $6,693,390. I recommend that these costs be disallowed because they are costs due to environmental violations, and they exceed the amount of costs required for CAMA compliance in the absence of environmental violations.

Q. PLEASE EXPLAIN THE THIRD CATEGORY OF EXPENSES WHICH YOU RECOMMEND BE DISALLOWED.

A. The third category is costs that must be excluded pursuant to the probation conditions of DEP's federal plea agreement. In the Memorandum of Plea Agreement, entered February 20, 2015, in the criminal action brought by the U.S. Department of Justice and the U.S. Attorney offices for the Eastern, Middle, and Western districts of North Carolina, Docket No. 5:15-CR-68-H, Duke Energy Progress agreed to make these payments:

$3.9 million fine for unlawful discharge in violation of the Clean Water Act at the H.F. Lee plant

$3.5 million fine for failure to maintain the riser in the 1978 ash basin in violation of the Clean Water Act at the Cape Fear plant

$3.5 million fine for failure to maintain the riser in the 1985 ash basin in violation of the Clean Water Act at the Cape Fear plant

$3.5 million fine for unlawful discharge in violation of the Clean Water Act at the Asheville plant

$10.5 million Community Service Payment though the National Fish and Wildlife Foundation, as a condition of probation

$5 million for wetlands mitigation, as a condition of probation

Restitution to victims in whatever amount the Court specifies

Restitution as directed by the Court Appointed Monitor, including payment for the Cape Fear Public Utility Authority to extend a water line to an affected community

$500 as a Special Assessment

> Funding of required nationwide and statewide Environmental Compliance Plans

The plea agreement further provides:

> ee. No Rate Increase Based Upon Monetary Penalties: The Defendant shall not reference the burden of, or the cost associated with, compliance with the criminal fines, the restitution related to counts of conviction, the community service payments, the mitigation obligation, the costs of the clean-up in response to the February 2, 2014, release at Dan River Steam Station, and/or the funding of the environmental compliance plans in any request or application for a rate increase on customers. Provided, however, that nothing in this Agreement shall, bar or prevent the Defendant from seeking appropriate recovery for restitution in connection with the remediation of bromide claims set forth in this Agreement or for costs which would have been incurred by the Defendant irrespective of the environmental compliance plans. Costs that would have been incurred irrespective of the environmental compliance plans include, by way of example only, costs for staffing and operating Central Engineering Services, ABSAT, Coal Combustion Products, or other similar organizations.

Q. HAVE YOU CONFIRMED THAT DEP EXCLUDED THESE COSTS FROM ITS RATE REQUEST, AS REQUIRED BY THE PLEA AGREEMENT?

A. DEP has stated that all these costs are excluded from its rate request.

Q. ARE THERE OTHER COAL ASH-RELATED COSTS THAT DEP HAS EXCLUDED FROM ITS RATE REQUEST?

A. Yes. DEP has excluded the "goodwill" payments to owners of drinking water wells in areas potentially affected by groundwater contamination, as well as other payments to well owners that are essentially settlements, including a stipend to cover twenty-five years of water bills and a program designed to guarantee neighbors of power plants the fair market value of their residential property should they decide to sell their property.

Q. YOU MENTION AN ADDITIONAL PUBLIC STAFF RECOMMENDATION THAT WOULD RESULT IN A SHARING OF THE ALLOWED COSTS. PLEASE EXPLAIN.

A. The Public Staff recommends that in addition to disallowance of costs in the three categories related to environmental violations, as discussed above, and the Garrett and Moore adjustments, the Commission further create a sharing of remaining coal ash costs between ratepayers and shareholders. The operation of the sharing mechanism and reasons for it are described in witness Maness' testimony. I believe the proposed sharing is reasonable because it would be the simplest way to equitably assign responsibility for coal ash costs. Counsel informs me that an equitable sharing is within the Commission's authority to approve, and in fact has been approved in cases of abandoned nuclear plant construction and environmental cleanup of manufactured gas plants.

An equitable sharing is particularly appropriate in light of the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws. The nature and extent of some coal ash environmental problems found at earlier dates are addressed in the Joint Factual Statement signed by Duke Energy as part of the DEP federal plea agreement. See **Lucas Exhibit No. 9** for excerpts from that Joint Factual Statement. Additionally, there is substantial evidence beyond the criminal case of violations beyond those admitted in the federal criminal case. There appear to be extensive violations of NPDES permits that have not been adjudicated and may never be the subject of penalty proceedings, but nonetheless indicate DEP non-compliance with environmental requirements. Two years following the Dan River Spill, DEQ found eight dam safety issues at DEP's coal ash impoundments. There is also evidence of numerous groundwater exceedances. DEP did not engage in comprehensive groundwater monitoring and remediation until the threat of litigation by environmental groups, the agency enforcement suit, the Dan River spill, and CAMA forced DEP to address the causes of groundwater exceedances. See the NPDES permit violations **Lucas Exhibit No. 5**, the groundwater exceedances shown in **Lucas Exhibit No.6,** and DEQ's dam safety order in **Lucas Exhibit No. 3.**

The sheer number of legal actions against DEP for coal ash environmental violations is also suggestive of the extent of the problem. No court has ever ruled that alleged 2L exceedances or unpermitted seeps did not exist; rather, settlements and dismissals have generally been on grounds that did not require findings on the existence of coal ash constituents contaminating State or federal waters or groundwater.

The approximately 8,000 groundwater exceedances currently reported to DEQ from DEP monitoring wells are further indication of the breadth of environmental violations. Those exceedances are undergoing DEQ review to compare them to background levels of the reported constituents. After seeing the data and DEP's proposed PBTVs, it is reasonable to conclude generally that there will be a number of exceedances that are attributable to migration of contaminants from DEP's ash basins.

The failure of Duke Energy to comply with environmental regulations was undoubtedly a contributing factor to adoption of both the CCR Rule and CAMA, which in turn led to new compliance costs. The Federal Register publication of the final CCR Rule cites environmental damage caused by Duke Energy facilities, and not just the Dan River plant, as part of the justification for the CCR Rule. The Dan River spill prompted the CAMA legislation – a strict schedule for closures that to the knowledge of the Public Staff is unmatched by any legislation in any other state. Moreover, DEP's non-compliance with NPDES permits and 2L rules would in all probability have led to cleanup costs from environmental litigation or enforcement even if the CCR Rule and CAMA had never been adopted. Those cleanup costs would have largely overlapped CCR Rule/CAMA compliance costs because impoundment closure would be a primary cleanup method.

In these circumstances, it would be unreasonable to charge ratepayers for all the coal ash compliance costs beyond the specific and limited disallowances the Public Staff has recommended. DEP has a great deal of culpability for compliance costs related to ash basin closures, and would likely have incurred most of those costs even without the CCR Rule and CAMA, whereas ratepayers are not culpable at all for those costs.

For the foregoing reasons, I believe the equitable sharing of coal ash management costs, as recommended in the testimony of Public Staff witness Maness, is reasonable in addition to the specific disallowances I have recommended.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Jay B. Lucas

I graduated from the Virginia Military Institute in 1985, earning a Bachelor of Science Degree in Civil Engineering. I also graduated from the Virginia Polytechnic Institute and State University in 1991, earning a Master of Science degree in Environmental Engineering. I have 32 years of engineering experience, and since joining the Public Staff in January 2000, have worked on utility cost recovery, renewable energy program management, customer complaints, and other aspects of utility regulation. I am a licensed Professional Engineer in North Carolina.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of		
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	SUPPLEMENTAL TESTIMONY OF JAY LUCAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Supplemental Testimony of Jay Lucas

On Behalf of the Public Staff

North Carolina Utilities Commission

November 14, 2017

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

A. My name is Jay Lucas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission. I am the same Jay Lucas who previously filed direct testimony on behalf of the Public Staff in this docket.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to make minor corrections in my direct testimony. Also, I am making changes to Lucas Exhibit Nos. 5 and 6 that were filed as part of my original testimony on October 20, 2017.

Q. PLEASE DESCRIBE THE MINOR CORRECTIONS YOU ARE MAKING TO YOUR ORIGINAL TESTIMONY.

A. On page 42, line 10, of my original testimony is a reference to Lucas Exhibit No. 6, which should read Lucas Exhibit No. 7.

On page 42, line 16, of my original testimony is a reference to Lucas Exhibit No. 7, which should read Lucas Exhibit No. 6.

On page 71, line 2, the words "beyond the criminal case" should be deleted.

Q. PLEASE DESCRIBE THE CHANGES THAT YOU ARE MAKING TO LUCAS EXHIBIT NO. 5.

A. On page 42, line 3, of my testimony I refer to Lucas Exhibit No. 5 as NPDES permit violations. I based this description on the label from the DEQ source document. Some of the numbers in the original exhibit are NPDES permit violations, but most of the numbers are exceedances of the groundwater standards, which are not NPDES permit violations.

Also, some of the numbers in Lucas Exhibit No. 5 reference groundwater exceedances and violations, which are also counted in Lucas Exhibit No. 6. In order to prevent double counting and to correct references to groundwater exceedances as NPDES violations, I have provided Revised Lucas Exhibit No. 5. The revised exhibit only contains NPDES permit violations, along with a note that it does not include discharges (including seeps) from coal ash basins that were <u>not</u> authorized under any NPDES permit and therefore were unlawful.

I obtained the data in Lucas Exhibit No. 5 from the Department of Environmental Quality's Monitoring Reports.

Q. PLEASE DESCRIBE THE CHANGES THAT YOU ARE MAKING TO LUCAS EXHIBIT NO. 6.

A. The Revised Lucas Exhibit No. 6 contains a list that numbers the groundwater standard <u>violations</u>. It also numbers the groundwater standard <u>exceedances</u> that, in the future, may or may not prove to be violations, depending on whether DEQ determines they are due to coal ash or due to natural background levels. The groundwater standards are listed in 15A NCAC 2L or listed in the interim maximum allowable concentrations (IMACs).

Q. DO ANY OF THESE CHANGES AFFECT YOUR CONCLUSIONS OR RECOMMENDATIONS?

A. No. My conclusions and recommendations remain the same.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BY MR. BURNETT:

Q. Mr. Maness, would you state your name and position for the record, please?

A. (Michael Maness) My name is Michael C. Maness. I am director of the accounting division with the Public Staff.

Q. And on October 20, 2017, did you cause to be prefiled in this proceeding 37 pages of direct testimony, a two-page appendix stating your qualifications, and Exhibits 1 through 3?

A. Yes, I did.

Q. And in November 2017, did you cause to be prefiled in this proceeding five pages of supplemental testimony and a Revised Exhibit 1 with revised schedules 1, 1-1, and 1-26?

A. I did.

Q. Do you have any corrections to your prefiled testimonies or exhibits?

A. Yes. I have three corrections to my --

COMMISSIONER GRAY: Sir, could you pull that microphone --

THE WITNESS: Yes. Thank you. I have three corrections to my prefiled testimony, on page 6, lines 2 and 3. On line 2 it says "mid-year cash flow convention." It should say "mid-month." And the same thing on line 3 where it says "beginning of year," it should say "beginning of month."

And then on page 24, line 14, the word "comination" appears -- and that is actually a real word, I discovered on looking it up -- but it should be "Commission."

BY MR. DROOZ:

Q. And is that all three of your corrections?

A. Yes.

MR. DROOZ: Mr. Chairman, the Public Staff moves that the prefiled testimonies of Mr. Maness be admitted into the record as if orally given from the stand, and that his exhibits be marked for identification as prefiled.

CHAIRMAN FINLEY: Mr. Maness' direct prefiled testimony consisting of 37 pages, and 2 pages of appendixes are copied into the record as if given orally from the stand, and his three direct exhibits are marked for identification as premarked in the filing. His supplemental testimony, consisting of 5 pages, is copied into the record as if given orally from the stand, and his Revised Supplemental Exhibit 1 is marked for identification as premarked in the filing.

(Whereupon, Direct Maness Exhibit Numbers 1 through 3, and Supplemental Maness Exhibit Number 1 marked for identification.)

(Whereupon, the prefiled direct and supplemental testimony of Michael Maness was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

October 20, 2017

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

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. **BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.**

A. My qualifications and duties are included in Appendix A.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to present certain accounting and ratemaking adjustments that I am recommending be adopted by the North Carolina Utilities Commission (Commission) for purposes of determining the rate increase to be approved for Duke Energy

Progress, LLC (DEP or the Company) in this proceeding. I am also taking adjustments recommended in certain areas by other members of the Public Staff and flowing them through my schedules so that they can be incorporated into the recommended rate increase determination.

Q. HOW ARE YOUR RECOMMENDED ADJUSTMENTS, AS WELL AS THOSE YOU ARE FLOWING THROUGH, BEING INCORPORATED INTO THE PUBLIC STAFF'S RECOMMENDED RATE INCREASE?

A. I have provided the aggregate impact of all the adjustments I am recommending or incorporating to Public Staff witness Darlene P. Peedin for inclusion in her Exhibit 1, in which she calculates the overall increase in the Company's revenue requirement recommended by the Public Staff, which is then used to determine the recommended rate increase.

Q. IN WHAT AREAS ARE YOU RECOMMENDING ADJUSTMENTS OR INCORPORATING ADJUSTMENTS RECOMMENDED BY OTHER MEMBERS OF THE PUBLIC STAFF?

A. I am recommending or incorporating adjustments in the following areas:

1. The ratemaking treatment of the costs of DEP's coal ash compliance and cleanup activities.
2. The amount of DEP's 2016 storm costs to be deferred and amortized, and the recommended amortization period.

3. The appropriate remaining useful life to be used for the meters that DEP plans to retire as part of its expedited installation of AMI meters.

I also discuss the appropriate ratemaking treatment for the jurisdictional allocation impacts of the increase in wholesale load resulting from DEP's purchase of generating capacity from certain wholesale customers. Finally, I discuss and provide support for Public Staff witness Roxie McCullar's adjustment to the inflation of production plant estimated terminal net salvage costs.

Q. PLEASE DESCRIBE YOUR RECOMMENDED AND INCORPORATED ADJUSTMENTS.

A. The adjustments are described below.

COSTS OF DEP'S COAL ASH MANAGEMENT ACTIVITIES

Q. PLEASE BRIEFLY DESCRIBE THE BACKGROUND OF DEP'S COAL ASH MANAGEMENT ACTIVITIES.

A. The background related to these activities is described in detail in the testimony of Public Staff witness Lucas. Briefly, however, DEP's coal ash (also called coal combustion residuals, or CCRs) management activities are being conducted in large part pursuant to the Environmental Protection Agency's (EPA) Coal Combustion Residual (CCR) rule, finalized in 2015, and North Carolina's 2014 Coal Ash Management Act (CAMA) (along with related statutes passed by the North Carolina General Assembly in 2015 and 2016).

Additionally, coal ash management costs are affected by compliance requirements, and non-compliance consequences, related to water quality and dam safety regulations.

Q. IN GENERAL, WHAT ADJUSTMENTS HAVE YOU MADE TO THE COMPANY'S COSTS OF COAL ASH MANAGEMENT?

A. I have made the following adjustments:

1. Adjustments to the coal ash management expenditures to reach a prudent and reasonable level of coal ash expenditures (at least provisionally), as recommended by Public Staff witnesses Vance F. Moore and L. Bernard Garrett, and Public Staff witness Jay Lucas.
2. Adjustments to the N.C. retail jurisdictional allocation factors to (a) allocate the costs DEP has identified as "CAMA Only" costs by the comprehensive allocation factor, rather than a factor that does not allocate costs to the South Carolina retail jurisdiction; and (b) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor.
3. Addition of return on deferred coal ash expenditures from September 2017 through January 2018, to bring the total balance up to the expected effective date of the rates approved in this proceeding.

4. Calculation of the return between January 1, 2015, and January 31, 2018, using a mid-year cash flow convention, rather than the beginning-of-year convention used by the Company.

5. Amortization of the balance of deferred coal ash expenditures at the beginning of February 2018 over a 28-year period, rather than the 5-year period proposed by the Company.

6. Reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base; this reversal, in conjunction with the 28-year amortization period, produces a reasonable sharing of the burden of coal ash expenditures between the Company's ratepayers and its shareholders.

7. Removal of the "run rate" proposed by DEP to recover additional coal ash management costs incurred from the date the rates approved in this proceeding become effective through the date rates become effective in DEP's next general rate case.

Q. CAN YOU EXPLAIN WHY THERE IS A DEFERRED BALANCE OF COAL ASH MANAGEMENT EXPENDITURES THAT DEC IS PROPOSING TO AMORTIZE FOR RATE RECOVERY BEGINNING WITH THIS PROCEEDING?

A. Yes. On December 21, 2015, Duke Energy Corporation (Duke Energy) filed a letter with the Commission indicating that DEP had established a regulatory asset account for purposes of accounting for costs related to its coal ash-related Asset Retirement Obligations (AROs). Subsequently, on December 30, 2016, in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, DEP and Duke Energy Carolinas, LLC (DEC), jointly filed a petition requesting that the Commission authorize each utility to defer certain costs related to compliance with state and federal environmental requirements associated with coal combustion residuals. On January 6, 2017, the Commission issued an order requesting comments on DEP's and DEC's petition.

Several parties, including the Public Staff, filed comments in response to the Commission's order. In its comments, filed on March 15, 2017, the Public Staff stated that in this particular case, the Public Staff believed that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfied the criteria for deferral for regulatory accounting purposes, subject to (a) the normal provision that this decision would be entered without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings; (b) recognition of the fact that given the complex task of determining what portion, if any, of these very unique deferred expenses should ultimately be approved for rate recovery in a general rate proceeding, any assumptions regarding such rate recovery should be especially discouraged; (c) the possibility that given the unusual circumstances of these costs, the Commission might determine that some sharing of the costs between ratepayers and shareholders is necessary to ensure that rates charged to customers are limited to an appropriate and reasonable amount; and (d) the determination of the method and length of amortization of any deferred costs.

In addition to not objecting to deferral of these expenses, the Public Staff indicated that the unique nature of the costs and the complexity of the issues surrounding the determination of ultimate rate recovery justified a limited delay in determining the beginning date of any amortization of the deferred expenses until the next respective general rate proceeding, which was expected to be filed sometime in 2017.

With regard to the deferral of a return on capitalized items, as well as deferral of carrying charges on the deferred expenses themselves, the Public Staff did not object to such a deferral. However, the comments indicated that the ultimate recoverability of those deferred returns in rates should be considered to be subject to the provisions generally set forth therein.

The Public Staff also identified several items unique to the topic of coal ash management that would need to be considered as part of the process of determining the appropriate amount of CCR costs that should be recovered from ratepayers, as well as the timing of that recovery. Those items included, but were not limited to, the prudence and reasonableness of the costs incurred; any fines, penalties, or other costs of resolving and/or remediating violations of law and regulations; any costs of settling legal disputes, or of resolving and/or remediating issues as part of a settlement; issues of jurisdictional allocation; whether the setting of fair and reasonable rates demands a sharing of costs between ratepayers and shareholders; and the appropriate and reasonable amortization period for any costs ultimately determined to be prudently incurred and reasonable for recovery from the ratepayers.

On April 19, 2017, DEP and DEC filed reply comments in the subdockets. On July 10, 2017, the Commission issued an order consolidating Docket No. E-2, Sub 1131 with this general rate case proceeding.

Q. **DOES THE PUBLIC STAFF CONTINUE TO SUPPORT THE DEFERRAL OF THE COMPANY'S COAL ASH EXPENDITURES AS REASONABLE?**

A. Yes. Based on the magnitude and unique nature of the costs, as well as the other reasons set forth in its Sub 1103 comments, the Public Staff continues to believe that prudently incurred coal ash expenditures should be allowed to be deferred for regulatory accounting purposes. However, in order to determine the amount of expenditures that should be recovered from the ratepayers, and the appropriate and reasonable method and timing of that recovery, several of the issues mentioned in the Public Staff's comments must first be addressed. The testimony filed in this proceeding by witnesses Moore and Garrett, witness Lucas, and myself address these issues, resulting in the Public Staff's recommended provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017.

Q. WHY DO YOU USE THE TERM PROVISIONAL?

A. I use this term because there are certain expenditures incurred during 2015 and 2016 for which the appropriateness of recovery, in the opinion of the Public Staff, may depend on the outcome of legal proceedings or other legal determinations. These categories of expenditures are described in the testimony of witness Lucas. Consequently, the Public Staff believes that the ultimate amount of 2015-2016 expenditures appropriate and reasonable for recovery should await the outcome of these legal situations and further Commission scrutiny of them. Should any of these expenditures be found to be imprudently incurred or otherwise unreasonable or inappropriate for recovery, the Public Staff will propose an appropriate adjustment in DEP's next general rate case.

Q. ARE THERE CERTAIN RATEMAKING APPROACHES TAKEN IN THIS PROCEEDING WITH WHICH YOU AGREE, GIVEN THE PUBLIC STAFF'S COMMENTS IN SUB 1103?

A. Yes. Consistent with its comments, the Public Staff does not object for purposes of this proceeding to the deferral of a return for the period January 2015 through January 2018 on likewise deferred prudent coal ash expenditures. Additionally, due to the magnitude and very unique nature of these costs, the Public Staff does not object to the beginning of the amortization being delayed until the effective date of the rates approved in this proceeding.[1]

Q. PLEASE PROCEED TO DISCUSS YOUR ADJUSTMENTS TO THE COMPANY'S RECOMMENDED LEVEL OF DEFERRED COAL ASH MANAGEMENT EXPENDITURES.

A. The first adjustment I am making is to reduce the coal ash management costs subject to deferral, based on the recommendations of Public Staff witnesses Moore, Garrett, and Lucas. The rationales for these adjustments are fully set forth in the testimonies of those witnesses, but they can be briefly described as follows:

1. Adjustments made in order to remove the costs associated with the removal of ash from the Sutton plant to Brickhaven

[1] For many types of deferred costs, the Public Staff typically recommends that amortization begin in the month of or the month following the incurrence of the costs.

(witnesses Moore and Garrett) – approximately $80.5 million, on a system basis.

2. Adjustments made to reduce the costs of ash processing at the Asheville plant to a more reasonable level (witnesses Moore and Garrett) – approximately $45.6 million, on a system basis.

3. Adjustments made to remove the costs of extraction and treatment of contaminated groundwater (witness Lucas) – approximately $6.7 million, on a system basis.

I have accumulated these costs and spread them in a reasonable manner throughout the January 2015 through August 2017 period, pursuant to guidance received from the applicable witnesses. This accumulation is set forth on Maness Exhibit 1, Schedule 1-2. The adjustments have then been used to reduce the monthly deferral of system-level costs set forth on Maness Exhibit 1, Schedule 1-1.

Q. **PLEASE DESCRIBE YOUR ADJUSTMENTS TO THE JURISDICTIONAL ALLOCATION FACTORS USED TO ALLOCATE SYSTEM COAL ASH COSTS TO N.C. RETAIL OPERATIONS.**

A. The first adjustment I have made to the allocation factors is to remove the distinction between those costs the Company describes as "CAMA Only" and the remainder of the coal ash costs. In her testimony, Company witness Bateman states that there is a small portion of coal ash management costs that is "specific to CAMA, unique to North Carolina and appropriate for direct assignment to North Carolina"; Company witness Kerin states that these costs include groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to North Carolina law. Consequently, the Company has utilized N.C. retail allocation factors for its self-described CAMA Only costs that do not allocate any of the system level costs to South Carolina retail operations. However, the Public Staff believes that even though some of the costs incurred by DEP are being incurred pursuant to North Carolina law, it is still fair and reasonable to allocate those costs to the entire DEP system, because the coal plants associated with the costs are being or were operated to serve the entire DEP system.

My second adjustment to the N.C. retail allocation factors is to use the energy allocation factor to allocate system level coal ash costs to North Carolina retail operations, rather than the demand-related production plant allocation factor utilized by the Company. I recommend this change because the coal ash costs are being incurred due to the fact that the coal ash was produced by the burning of coal to produce energy over the years and, like the cost of coal, should be allocated by energy, and not peak demand. Therefore, I believe that the energy allocation factor should be used to determine the North Carolina retail portion of these costs.

These allocation factor adjustments are reflected in the deferral balance calculated on Maness Exhibit 1, Schedule 1-1.

Q. WHY HAVE YOU ADDED A RETURN FOR THE PERIOD SEPTEMBER 2017 THROUGH JANUARY 2018 TO THE DEFERRED BALANCE OF COAL ASH COSTS?

A. The Company has updated its proposed balance of deferred coal ash management costs, with an accrued return, through August 2017. However, the rates in this proceeding are not expected to go into effect until February 1, 2018. Therefore, in order to capture all of the costs, including return, related to the January 2015 – August 2017 underlying coal ash costs, I consider it reasonable to add the return accumulated on the principal amount through January 2018. By doing that, the costs related to that principal amount can be isolated for ratemaking treatment from coal ash costs incurred after August 2017 and any allowed return on those costs. This adjustment is set forth on Maness Exhibit 1, Schedule 1-1.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CHANGE THE METHOD OF ACCRUING THE RETURN ON DEFERRED COAL ASH COSTS FROM ONE EMPLOYING A BEGINNING-OF-MONTH CASH FLOW ASSUMPTION TO ONE EMPLOYING A MID-MONTH CASH FLOW ASSUMPTION.

A. The Company has used a return calculation methodology that accrues a return for each month assuming that all cash flows during the month occur at the very beginning of the month. I believe this assumption to be unrealistic. I have made an adjustment, on Maness Exhibit 1, Schedule 1-1, to use a mid-month cash flow assumption, which basically assumes that the cash flows in each month are experienced throughout the month, rather than at the beginning.

Q. PLEASE EXPLAIN YOUR FOURTH AND FIFTH ADJUSTMENTS, THE RECOMMENDATION TO AMORTIZE THE DEFERRED BALANCE OF JANUARY 2015 THROUGH AUGUST 2017 COAL ASH COSTS OVER 28 YEARS, AND THE RECOMMENDATION TO REVERSE THE COMPANY'S INCLUSION OF THE UNAMORTIZED COSTS IN RATE BASE.

A. The Company has recommended that the costs of coal ash management be amortized over five years for ratemaking purposes in this proceeding. In my opinion, that is simply too short an amortization period for costs of the magnitude and nature of these. Instead, the Public Staff has been guided in its choice of amortization period for these costs in this proceeding by its belief that it is most reasonable and appropriate for coal ash costs, even after specific imprudently incurred or otherwise unreasonable amounts have been discovered and disallowed for recovery, to be shared equitably between the ratepayers and the Company's shareholders.

Q. WHY DOES THE PUBLIC STAFF BELIEVE COAL ASH COSTS, AFTER REMOVAL OF SPECIFICALLY DISALLOWABLE AMOUNTS, SHOULD BE SHARED BETWEEN THE RATEPAYERS AND SHAREHOLDERS?

A. There are two general reasons why the sharing of costs for coal ash management is a reasonable and appropriate for ratemaking purposes. First, as discussed in more detail by Public Staff witness Lucas, the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws, supports ratemaking that leaves a large share of the costs for DEP shareholders to pay.

Second, there is a history of approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. Such sharing between ratepayers and shareholders has been approved for costs of abandoned nuclear construction and for environmental cleanup of manufactured gas plant facilities.

Q. HOW DOES THE PUBLIC STAFF ACHIEVE THIS RECOMMENDED SHARING?

A. The first step in achieving a sharing is to remove the unamortized amount of the deferred expenses from rate base. As a result of taking this step, the Company will not be allowed to earn a return from the ratepayers on the unamortized balance while the deferred costs are being amortized. The second step is to choose an amortization period that will result in a reasonable and appropriate sharing of the costs.

Q. IS EXCLUDING DEFERRED EXPENSES OR LOSSES FROM RATE BASE LEGAL UNDER THE NORTH CAROLINA GENERAL STATUTES?

A. Yes. Pursuant to G.S. 62-133(b)(1), the only costs that the Commission is required to include in rate base are (1) the "reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period ...", and (2) in some circumstances, the costs of construction work in progress. I am advised by counsel that beyond those requirements, what is and what is not allowed in rate base is fully within the legal discretion of the Commission to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers. Moreover, G.S. 62-133(d) requires the Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates."

The Commission has taken this approach several times in past cases, most often in the cases of nuclear and coal plants abandoned prior to commencing commercial operation, including, specifically for DEP, the abandonment losses related to Harris Units 2, 3, and 4 and

Mayo Unit 2.[2] This specific issue has also come before the North Carolina courts. In 1989, the North Carolina Supreme Court affirmed the Commission's decision that reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs. In State ex rel. Utilities Com. v. Thornburg, 325 N.C. 463 (1989), the Attorney General had sought exclusion of all abandonment costs related to the Harris Nuclear Plant. However, the Commission allowed amortization of the abandonment costs, with no return on the unamortized balance. The Court ruled that the Commission was acting within its discretion:

> [T]he Commission's order does not err as a matter of law in authorizing CP&L to continue to recover a portion of the cancellation costs of the abandoned Harris Plant as operating expenses through amortization. The Commission's determination was supported by several findings and conclusions. First, the [***26] Commission found that although "[t]his case must of course be decided on the basis of North Carolina statutes" the "majority of courts and commissions that have dealt with this issue have allowed ratemaking treatment of abandonment losses, usually as operating expenses." Second, the Commission concluded "that a liberal interpretation of the operating expense element of ratemaking so as to include the Harris abandonment losses is appropriate herein." Last, the Commission found further support for its conclusion was provided by N.C.G.S. § 62-133(d), which allows the Commission to consider all material facts in the record in determining rates.

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[2] See in particular the Evidence and Conclusions for Finding of Fact No. 11 in the *Commission's Order Granting Partial Increase in Rates and Charges*, issued on August 5, 1988, in Docket No. E-2, Subs 537 and 333.

> . . . .
>
> Last, we disagree with the Attorney General's contention "that strong policy considerations support the disallowance of [cancellation] expenses." We note that jurisdictions have generally dealt with the allocation of cancelled plant costs in one of the following three ways:
>
> (1) recovery of all of the costs from ratepayers, by allowing amortization of the investment plus a return on the unamortized balance;
>
> (2) recovery of all costs from shareholders through a total disallowance of recovery in rates, instead requiring the utility to write off the entire amount in a single year; or
>
> (3) recovery from ratepayers and shareholders through amortization of costs in rates over a period of years, with no return on [***34] the unamortized balance.
>
> . . . Strong policy considerations support the Commission and commentators who have concluded that method three is the best of the three alternatives in that it promotes "an equitable sharing of the loss between ratepayers and the utility stockholders."
>
> . . . .
>
> On this record, the Commission's continued use of method three is within the Commission's discretion, and this Court will not disturb that decision.

Similarly, environmental costs have been allowed to be deferred as regulatory assets, and amortized with no return on the unamortized balance, in cases involving manufactured gas plants (MGPs). One example can be found in the Commission's October 7, 1994, Order Granting a Partial Rate Increase in Docket No. G-5, Sub 327. In that case Public Service Company of North Carolina (PSNC) owned several sites that were previously operated as MGPs. The MGPs had ceased operations in the early 1950s. At the time of the rate case, the MGP sites were currently under investigation pursuant to environmental law. In its Order, the Commission concluded that deferral and amortization of MGP clean-up costs in a general rate case, rather than through a tracker, would result in more stable rates than otherwise. Furthermore, the Commission concluded that the unamortized balance of MGP costs should not be included in rate base, resulting in a sharing of clean-up costs between ratepayers and shareholders that would provide PSNC with motivation to minimize its costs.

Q. COMPANY WITNESS WRIGHT STATES IN HIS TESTIMONY THAT THE COAL ASH DISPOSAL COSTS THAT DEP IS SEEKING TO RECOVER IN THIS CASE ARE A "USED AND USEFUL" COST. DO YOU AGREE?

A. No. In North Carolina utility regulation, the term "used and useful" only applies to utility plant. DEP's accrued coal ash management costs may qualify as regulatory assets, but they are not utility plant. They may be prudently incurred in support of utility plant (or former utility plant), but they themselves are not utility plant, nor are they "used and useful." The Commission is under no legal obligation to include them in rate base or to otherwise allow a return on them to be recovered or accrued.

Q. PLEASE DESCRIBE HOW THE SECOND STEP YOU DESCRIBED PREVIOUSLY, THE CHOICE OF AN AMORTIZATION PERIOD, CAN BE USED TO ACHIEVE A SHARING OF COSTS BETWEEN THE UTILITY AND ITS RATEPAYERS.

A. Once it has been determined that the unamortized balance of the coal ash costs will not be included in rate base, the ability of the utility to recover those cost at a 100% level becomes entirely dependent upon the speed at which recovery can be achieved. The utility has already spent the money represented by the deferred costs in question; therefore, it will be required to borrow money or use equity to finance the spent costs until it can recover them from the ratepayers. If the utility was able to recover the total cost immediately, it would recover all of the costs at a 100% level; however, the ratepayers would also lose all of the time value of money that could be provided to them by a reasonable amortization period. Another way to look at this is that in that immediate recovery circumstance, the utility recovers 100% of the present value of the deferred costs at the time of deferral, and the ratepayers bear 100% of that cost. However, as the delay in utility recovery (i.e., the amortization period) increases, the utility's financing costs increase, and the burden of the loss of the time value of money on the ratepayers decreases. The utility recovers a lesser amount and percentage of the present value of the underlying cost, and the ratepayers bear less of the burden.

Q. WHAT AMORTIZATION PERIOD DOES THE PUBLIC STAFF RECOMMEND IN THIS CASE FOR THE COMPANY'S COAL ASH COSTS AS ADJUSTED BY THE PUBLIC STAFF?

A. As shown on Maness Exhibit 1, Schedule 1, the Public Staff recommends an amortization period of 28 years beginning on the date the rates approved in this proceeding become effective.

Q. WHAT SHARING PERCENTAGE DOES A 28-YEAR AMORTIZATION PERIOD PRODUCE?

A. At the net-of-tax overall rate of return recommended by the Public Staff, a 28-year amortization period results in the ratepayers bearing approximately 50% of the present value of the January 2015 – August 2017 deferred costs at February 1, 2018 (with a return accrued to that point). The Public Staff believes that this level of sharing is reasonable and appropriate for the reasons discussed above.

Q. IN THE RECENT DOMINION NORTH CAROLINA POWER (DNCP) CASE, THE PUBLIC STAFF AGREED TO AN AMORTIZATION PERIOD OF FIVE YEARS FOR COAL ASH COSTS, WITH THE UNAMORTIZED BALANCE INCLUDED IN RATE BASE. WHY

ARE YOU RECOMMENDING SUCH A DIFFERENT TREATMENT IN THIS CASE?

A. One of the reasons for the different recommendation is sheer magnitude. In the DNCP case, the total paid-to-date system costs in question were only approximately 19% of the total paid-to-date system costs at issue in this case. I would also like to point out that the stipulation filed by the Company and the Public Staff in that proceeding stated that "Notwithstanding this agreement, the Stipulating Parties further agree that the appropriate amortization period for future CCR expenditures shall be determined on a case-by-case basis."

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S RECOMMENDATION WITH REGARD TO THE EXPECTED LEVEL OF ONGOING N.C. RETAIL ANNUAL COAL ASH MANAGEMENT COSTS OF APPROXIMATELY $129 MILLION THAT THE COMPANY PROPOSES TO INCLUDE IN THE REVENUE REQUIREMENT IN THIS CASE.

A. The Public Staff agrees with the Company's proposal for an ongoing regulatory asset/liability to capture unrecovered prudently incurred and reasonable coal ash costs incurred after August 31, 2017, but opposes the establishment of an amount to be recovered on an ongoing basis between this proceeding and the Company's next general rate case. The main reason for the Public Staff's opposition is that it will potentially make future equitable sharing of the costs of coal ash costs much harder to achieve. For example, were the Commission to approve the recovery of 100% of the estimated annual costs on an ongoing basis between this rate case and the next one, a significant adjustment would be necessary in the rate case to "rebalance" the scales to an overall 50% sharing of the costs incurred after August 2017. If there were few unrecovered costs at the time of the next case, the necessary re-balancing might well require that money be flowed back to the ratepayers through future amortization, instead of the Company collecting those unrecovered costs.

From a practical standpoint, this problem could be addressed by only allowing the Company to recover on an ongoing basis the same percentage of costs that the Commination had approved for the ratepayer to bear in this proceeding. However, counsel for the Public Staff has advised me that such an approach might not hold up to legal scrutiny. Therefore, the Public Staff recommends that no ongoing recovery of annual future costs be allowed; instead, such costs should be deferred for consideration of amortization in the Company's next general rate case.

Q. WHAT DOES THE PUBLIC STAFF RECOMMEND WITH REGARD TO THE ACCRUAL OF A RETURN ON THE REGULATORY

ASSET CREATED BETWEEN NOW AND THE NEXT RATE CASE FROM THE ACCUMULATION OF POST-AUGUST 2017 COAL ASH COSTS?

A. The Public Staff recommends that the accrual of a return between the two rate cases be allowed by the Commission, at the net-of-tax rate of return applied to the balance of the regulatory asset, net of associated accumulated deferred income taxes. At the time of the next general rate case, the Commission can determine the appropriate sharing of the regulatory asset through amortization at that point in time.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING COAL ASH COSTS?

A. Yes. The Public Staff is aware that Duke Energy has filed suit against certain of its insurers to recover coal ash management costs under its policies with those insurers. Duke Energy has stated that if it does recover on any of those claims, that recovery will be credited against coal ash management costs to be recovered from its ratepayers.

DEFERRED 2016 STORM COSTS AND AMORTIZATION PERIOD

Q. PLEASE DESCRIBE THE CIRCUMSTANCES SURROUNDING THE PROPOSED DEFERRAL OF 2016 STORM COSTS.

A. On December 16, 2016, in Docket No. E-2, Sub 1131, DEP filed a petition with the Commission requesting an accounting order authorizing the Company to establish a regulatory asset account to defer certain costs incurred to repair and restore its system following storms incurred in 2016 (2016 storm costs). In the petition, DEP requested authorization to defer the incremental N.C. retail operations and maintenance (O&M) expenses, depreciation expense on capital investments, return on undepreciated capital costs, and carrying costs incurred in relation to the major storms it experienced in 2016, reduced by the $12.7 million in normalized storm expenses approved in its last general rate case (Docket No. E-2, Sub 1023).

On March 15, 2017, the Public Staff filed its Initial Comments in the docket. In those Comments, for the reasons set forth therein, the Public Staff recommended that the Company only be allowed to defer the difference between its actual incremental O&M expense related to 2016 storm costs and a normal amount of $27.4 million (a deferral estimated at that time to be approximately $68.8 million). The Public Staff also recommended that no deferral of depreciation expense, return on undepreciated capital costs, or carrying costs be allowed. Finally, the Public Staff recommended that DEP be required to amortize the deferred costs over a 10-year period, beginning in October 2016.

On April 12, 2017, DEP filed its Reply Comments in Sub 1131. In its Reply Comments, the Company continued to maintain that its proposed deferral was appropriate, including the use of the normalized O&M amount from the last rate case to determine the deferred O&M amount, and the deferral of depreciation expense, return, and carrying costs. The Company also stated that it believed the amortization of the deferred cost should not begin until its next general rate case. As part of its argument for its proposed beginning date, the Company referred to certain financial accounting guidance it has received in the past few years regarding the appropriate recording of regulatory assets for financial statement purposes under Generally Accepted Accounting Principles (GAAP).

On March 24, 2017 and April 17, 2017, respectively, pursuant to a Commission order issued on March 23, 2017, DEP and the Public Staff each filed workpapers supporting their arguments. On July 10, 2017, the Commission issued an Order consolidating Sub 1131 with this general rate case proceeding.

In her testimony in this proceeding, using the methodology proposed by the Company in its petition, Company witness Bateman calculates a projected N.C. retail deferral balance of approximately $81.5 million. She recommends that this amount be amortized over a three-year period.

Q. WHAT POSITION DOES THE PUBLIC STAFF NOW TAKE REGARDING DEFERRAL AND AMORTIZATION OF STORM COSTS?

A. The Public Staff maintains that the position it took in its Initial Comments filed in Sub 1131 continues to be appropriate and reasonable: that the Company only be allowed to defer the difference between its actual incremental O&M expense related to 2016 storm costs and a normal amount of $27.4 million (a deferral estimated at that time to be approximately $68.8 million); that no deferral of depreciation expense, return on undepreciated capital costs, or carrying costs be allowed; and that DEP be required to amortize the deferred costs over a 10-year period, beginning in October 2016. The reasons for the Public Staff position are laid out in detail in its Initial Comments, which are attached to my testimony as Maness Exhibit 3. A summary of these reasons is as follows:

1. Merely because the storm costs incurred in a given year are greater than $12.7 million, it cannot simply be assumed that the larger expense is extraordinary. In order to be considered extraordinary, and thus suitable for deferral, an expense should not simply be in excess of the level set in the previous rate case; it should be extraordinarily large in magnitude.

2. In this particular case, because the actual storm expenses included in the 10-year average spanned a wide range of annual amounts, from one annual amount as low as $1.8 million to one as high as $27.2 million, and because, in the 14-year period from 2002 through 2015, the Company incurred storm costs ranging between $22.9 million and $27.4 million in five years, the Public Staff believes that at least $27.4 million of the $96.2 million in 2016 North Carolina retail storm expenses should be considered normal for purposes of the Company's deferral request.

3. Historically, the Commission has amortized storm damage expenses over spans of time ranging from 40 months to ten years. Given the large size of the deferral recommended in this case, the Public Staff recommends that the deferred costs approved by the Commission be amortized for regulatory accounting purposes over a ten-year period.

4. It has been the historical practice of the Commission to begin the amortization of single-storm deferrals in the month the storm occurs. In this case, because the majority of 2016 storm costs were incurred in the latter part of the year (even though the entirety of the year's cost is being considered), the

Public Staff recommends that the amortization be required to begin no later than October 2016.

5. The Public Staff is not aware of any Commission precedent supporting deferral of the depreciation expense and associated carrying costs resulting from storm damage.

Q. WHAT IS YOUR OPINION REGARDING THE ACCOUNTING GUIDANCE PRESENTED BY THE COMPANY TO SUPPORT DELAYING THE BEGINNING OF THE AMORTIZATION OF THE DEFERRED STORM COSTS UNTIL THIS CASE?

A. Based on discussions with Company personnel during this proceeding, it is apparent that stricter criteria may be applied by external auditors in the current timeframe than have been applied in the past regarding the Company's ability to record a regulatory asset for GAAP financial accounting purposes. However, I do not believe it is appropriate for the Financial Accounting Standards Board or the Company's external financial statement auditors to control the Commission's decisions with regard to regulatory accounting or ratemaking purposes. The audited financial statements of the Company are intended to reflect the economic effects of actions taken by regulators, not control them. It is the Public Staff's opinion that for storm costs and, in general, other events that cause fluctuations in utility income between rate cases, it is most appropriate and reasonable for the Company to begin amortizing deferred costs into cost of service immediately. The purpose of deferral accounting is not to preserve costs for an indefinite period of time, when the Commission does not know when the next general rate case might be. Only in unusual circumstances, where costs are extremely high and/or extremely unusual, or in cases where a general rate case is pending, and the Commission particularly wants to synchronize the recognition of a deferred costs and the approval of new rates, is the delay of beginning an amortization generally appropriate.

Q. WHAT ARE THE IMPACTS OF THE PUBLIC STAFF'S RECOMMENDATION ON EXPENSES AND RATE BASE IN THIS CASE?

A. The determination of the appropriate and reasonable deferred 2016 storm cost balance is set forth on Peedin Exhibit 1, Schedule 2-1(b). Essentially, this calculation involves subtracting the appropriate normal storm cost amount ($27,400,000) from the Company's most recent estimate of N.C. retail incremental 2016 storm costs ($80,152,000). The resulting initially deferrable amount, $52,752,000, is divided by ten to produce the annual amortization expense, which is added to annual storm expenses on Peedin Exhibit 1, Schedule 3-1(o). To determine the appropriate rate base balance at the expected effective date of the rates to be approved in this case, 1.33 years of amortization (October 2016 through January 2018) are deducted from the initial deferred cost balance, resulting in a February 1, 2018, deferred cost balance of $45,736,000. Because I have updated the balance to the expected effective date of rates, I have not further reduced the balance for a year of amortization.

THE APPROPRIATE REMAINING USEFUL LIFE FOR METERS BEING REPLACED BY AN EXPEDITED INSTALLATION OF AMI METERS

Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING THE APPROPRIATE REMAINING USEFUL LIFE FOR METERS THAT ARE TO BE REPLACED BY ADVANCED METERING INFRASTRUCTURE (AMI) METERS AS PART OF THE REPLACEMENT PROGRAM PLANNED BY THE COMPANY.

A. Company witness Bateman states in her testimony that the Company is requesting permission to establish a regulatory asset for meters that will be replaced under DEP's AMI deployment program. She further states that the depreciation study recovers the remaining net book value of the meters to be replaced over three years, the expected deployment period for the program.

I do not oppose the establishment of a regulatory asset to track the retirement and remaining depreciation of the replaced meters.

However, I do not believe that customers should be charged the entire cost of the replaced meters over a three-year period. Pursuant to information received from the Company, these meters have an average estimated remaining useful life of 18.3 years. I recommend that the meters be depreciated using this remaining useful life, not three years. There is no reason that the recovery of the remaining cost of the retired meters from the Company's customers should be accelerated.

I have provided the 18.3 year remaining useful life to Public Staff witness McCullar for her use in developing the Public Staff's recommended depreciation rates.

JURISDICTIONAL ALLOCATION IMPACTS RELATED TO INCREASE IN WHOLESALE LOAD

Q. PLEASE DISCUSS THE JURISDICTIONAL ALLOCATION IMPACTS OF THE INCREASE IN WHOLESALE LOAD RESULTING FROM DEP'S PURCHASE OF GENERATING CAPACITY FROM CERTAIN OF ITS WHOLESALE CUSTOMERS.

A. In DEP's recent Joint Agency Asset Rider (JAAR) filing, DEP made an adjustment to remove most of the effects of the allocation credit from the prospective JAAR. The allocation credit recognizes the benefit of the reduction in North Carolina retail allocation factors resulting from the addition of the North Carolina Eastern Municipal

Power Agency (NCEMPA) load formerly served by NCEMPA's undivided ownership interests to DEP's native system load requirements, a benefit that has been included in the JAAR in prior proceedings. Company witness LaWanda Jiggetts indicated in her testimony that the reason DEP excluded most of the allocation credit from the proposed prospective rates is that the Company had reflected the credit in the base rates it has proposed in this general rate case.

I recommended an adjustment to add back the eleven months of the allocation credit excluded from the prospective rate calculation by the Company. The proposed inclusion of the allocation credit in base rates was reflected in the Company's filing in Sub 1142; thus, it had not yet been approved by the Commission. The Commission's order approving rates in Sub 1142 was expected to be issued prior to February 1, 2018. However, the proposed JAAR rates were scheduled to go into effect on December 1, 2017. Therefore, making an assumption in the JAAR proceeding that the Company's proposed base rate treatment of the allocation credit would be approved was somewhat premature. The Public Staff believed it was instead reasonable to keep the full annual allocation credit in the JAAR prospective revenue requirement calculation for purposes of determining the JAAR rates to go into effect on December 1, 2017. The Public Staff also recommended that should the Commission approve, in Sub 1142, the transfer of the allocation credit to base rates, the Commission also provide for an immediate filing of a proposed revised set of JAAR rates that would conform to the Sub 1142 order. Any undercollection of JAAR revenue requirements during the interim between December 1, 2017, and the approval of revised JAAR rates in the first part of 2018 could be included in the regular true-up of JAAR revenue requirements for the applicable months, whenever those months are trued up in a future JAAR annual proceeding. The Company agreed to this approach.

Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION REGARDING THE APPROPRIATE TREATMENT OF THE ALLOCATION CREDIT?

A. After review, the Public Staff agrees with the Company's recommendation to move the allocation credit effect to base rates. Therefore, the Public Staff recommends that the Commission provide for a special JAAR proceeding to be held immediately after the conclusion of this general rate case to make the appropriate adjustment to remove the allocation credit from the JAAR.

INFLATION OF PRODUCTION PLANT ESTIMATED TERMINAL NET SALVAGE COSTS

Q. **HAVE YOU REVIEWED PUBLIC STAFF WITNESS MCCULLAR'S RECOMMENDATION TO COLLECT THE ESTIMATED TERMINAL NET SALVAGE COSTS IN YEAR 2023 DOLLARS?**

A. Yes. I am not presenting testimony on behalf of the Public Staff on depreciation, but I wanted to see whether Ms. McCullar's proposal would cause rates for terminal net salvage to be backloaded, i.e., whether future ratepayers would pay more (in real dollars) for terminal net salvage, including the impact on rate base. I used costs for DEP's Roxboro 4 Plant to make calculations, as shown on Maness Exhibit 2.

Q. **WHAT DID YOUR CALCULATIONS SHOW?**

A. By inflating the dollars to be recovered from current ratepayers to 2033 amounts (the traditional method), the Company's proposal frontloads the collection of costs for terminal net salvage, as is shown by the line that begins in the upper left corner of my graph. This is the traditional ratemaking approach taken for depreciation expense by this Commission, but other approaches have been at certain times for cost of removal, namely nuclear decommissioning. The annual inflation-adjusted approach, as shown on Maness Exhibit 2 for Roxboro, still leaves the revenue requirement for the collection of net terminal salvage costs still slightly frontloaded, but the slope of its line on the graph is almost zero. Thus, at least in this example, backloading of the revenue requirement does not occur, particularly since witness McCullar is allowing five years of inflation to be recognized in the first year of depreciation, not just one year, as is shown in the example.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

MICHAEL C. MANESS

I am a graduate of the University of North Carolina at Chapel Hill with a Bachelor of Science degree in Business Administration with Accounting. I am a Certified Public Accountant and a member of both the North Carolina Association of Certified Public Accountants and the American Institute of Certified Public Accountants.

As Director of the Accounting Division of the Public Staff. I am responsible for the performance, supervision, and management 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. I have been employed by the Public Staff since July 12, 1982.

Since joining the Public Staff, I have filed testimony or affidavits in several general, fuel, and demand-side management/energy efficiency rate cases of the utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC., and Virginia Electric and Power Company (Dominion Energy North Carolina) as well as in several water and sewer general rate cases. I have also filed testimony or affidavits in other proceedings, including applications for certificates of public convenience and necessity for the construction of generating facilities, applications for approval of self-generation deferral rates, applications for approval of cost and incentive recovery mechanisms for electric utility demand-side management and energy efficiency (DSM/EE) efforts, and applications for approval of cost and incentive recovery pursuant to those mechanisms.

I have also been involved in several other matters that have come before this Commission, including the investigation undertaken by the Public Staff into the operations of the Brunswick Nuclear Plant as part of the 1993 Carolina Power & Light Company fuel rate case (Docket No. E-2, Sub 644), the Public Staff's investigation of Duke Power's relationship with its affiliates (Docket No. E-7, Sub 557), and several applications for business combinations involving electric utilities regulated by this Commission. Additionally, I was responsible for performing an examination of Carolina Power & Light Company's accounting for the cost of Harris Unit 1 in conjunction with the prudence audit performed by the Public Staff and its consultants in 1986 and 1987.

I have had supervisory or management responsibility over the Electric Section of the Accounting Division since 1986, and also was assigned management duties over the Water Section of the Accounting Division during the 2009-2012 time frame. I was promoted to Director of the Accounting Division in late December 2016.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of		
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	SUPPLEMENTAL TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

Supplemental Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

November 22, 2017

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

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff). I am the same Michael C. Maness who previously filed direct testimony on behalf of the Public Staff in this docket.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to present certain revisions to the ratemaking adjustments that I am recommending for the costs of Duke Energy Progress' (DEP or the Company) coal ash activities. I have provided my revised adjustments to Public Staff witness Darlene P. Peedin for inclusion in her revised Exhibit 1, in which she calculates the revised overall increase in the Company's revenue requirement recommended by the Public Staff in accordance with the Agreement and Stipulation of Partial Settlement (Stipulation) between DEP and the Public Staff, filed in this proceeding on this date.

Q. WHAT REVISIONS ARE YOU MAKING TO YOUR RECOMMENDED ADJUSTMENTS IN THE AREA OF COAL ASH COSTS?

A. My revisions apply solely to my recommended adjustment to the amortization expense for deferred environmental (coal ash) costs, and consist of the following:

1. Reflection of the reduction in the adjustment related to the Asheville site recommended by Public Staff witnesses Garrett and Moore, in their supplemental testimony filed in this proceeding on November 20, 2017, from approximately $46 million to approximately $29 million.

2. A reduction in my recommended amortization period for deferred coal ash costs from 28 years to 26 years.

Q. **WHAT IMPACT DOES REFLECTION OF WITNESSES GARRETT'S AND MOORE'S REDUCTION HAVE ON YOUR RECOMMENDED AMORTIZATION EXPENSE?**

A. The reduction in the adjustment increases the amount of costs remaining to be amortized with no return on the unamortized balance.

Q. **WITH REGARD TO YOUR SECOND REVISION, WHY HAVE YOU REDUCED THE AMORTIZATION PERIOD TO 26 YEARS?**

A. As reflected in the Stipulation, the Public Staff and DEP have agreed to a weighted overall rate of return of 7.09% for purposes of setting rates in this proceeding. In my initial direct testimony, I state that the Public Staff believes that a sharing rate of 50% between ratepayers and shareholders for coal ash costs, after specific imprudently incurred or otherwise unreasonable amounts have been discovered and disallowed for recovery, is most reasonable and appropriate. The overall rate of return, net of income taxes, affects the number of years of amortization needed to achieve this 50% sharing. Because of the increase in the rate of return from that initially recommended by the Public Staff to the 7.09% agreed to in the Stipulation, the amortization period necessary to achieve an approximate 50% sharing has decreased to 26 years.

Q. WHAT IS THE IMPACT OF THESE TWO REVISIONS ON YOUR RECOMMENDED AMORTIZATION EXPENSE?

A. Reflection of the two revisions results in an increase in the recommended North Carolina retail amortization expense from $5,248,000 to $6,093,000, and thus a reduction in our recommended adjustment from $(42,015,000) to $(41,170,000). My revised adjustment is set forth on Maness Revised Exhibit 1, attached to my supplemental testimony.

Q. DOES THE INCREASE IN YOUR RECOMMENDED AMORTIZATION EXPENSE AFFECT RATE BASE?

A. No. The Public Staff continues to recommend that deferred coal ash costs be excluded from rate base in their entirety, in order to achieve an equitable sharing of those costs between the ratepayers and the shareholders.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

BY MR. DROOZ:

Q. And we have handed out written copies of the testimony summaries.

Mr. Lucas, would you please deliver the summary of your testimony at this point?

A. (Jay Lucas) Yes. The purpose of my testimony is to make recommendations to the Commission on the Public Staff's position on DEP's general rate case regarding whether DEP should be permitted to recover coal ash disposal costs in the fuel rider and whether DEP is culpable for environmental problems created by its management of coal ash.

DEP seeks to recover, through the fuel adjustment clause, the cost of paying its contractor, Charah, LLC, to excavate coal ash from the coal ash ponds at the Sutton plant, transport it to a former clay mine in Chatham County, and deposit it there. The Public Staff recommends that the Commission exclude the Charah costs for disposal of coal ash from the fuel rider, because they are not a sale of coal combustion by-products. The substance of the transaction is a contract for services, not a sale.

I have reviewed the state and federal regulatory framework on coal ash litigation against

DEP, and DEP's alleged environmental violations. The Public Staff recommends the exclusion from rates of $88,000 in outside legal fees for environmental litigation where there is strong evidence of environment violations, and $6.7 million of costs for extracting and treating contaminated groundwater that were part of the settlement in that same litigation. However, for most of the costs related to environmental violations, it is not feasible to calculate specific costs for several reasons. First, the extent of groundwater violations is still being determined through Department of Environmental Quality review and through pending lawsuits. Second, it would be too speculative to estimate the net avoidable costs of remediation on the basis of, what if DEP had installed liners when it constructed its ash basins? And it would be too speculative to estimate the environmental remediation costs that would have been imposed by enforcement actions on the basis of, what if the federal CCR rule and CAMA had not forced cleanup through closure of ash basins?

DEP seeks recovery of what it calls environmental compliance costs, but that label masks the fact that many of these costs would have been incurred to clean up DEP's environmental violations even without the CCR rule or CAMA. The Commission has the authority to decide what are just and reasonable rates. The Public Staff -- it would not be just and reasonable to put the cost burden of DEP's failure to comply with environmental regulations entirely on customers.

The Public Staff is not saying that DEP's environmental noncompliance problems are the result of imprudence, because my review did not examine what Duke Energy knew or should have known about coal ash contamination at the time the ash basins were constructed. Instead, I maintain that DEP is culpable for environmental violations because the Company failed to meet its legal duty to protect ground and surface waters. Therefore, the Company should have some responsibility for paying for coal ash cleanup costs. This recommendation is one basis for the equitable sharing in the testimony of Public Staff Witness Maness.

This completes my summary.

Q. Mr. Maness, would you deliver your summary?

A. (Michael Maness) The purpose of my testimony is to recommend accounting and ratemaking adjustments in the following areas:

First, the ratemaking treatment of the costs of Duke Energy Progress' coal ash compliance and cleanup activities; second, the amount of DEP's 2016 storm costs to be deferred and amortized and the recommended amortization period; third, the appropriate remaining useful life to be used for the meters that DEP plans to retire as part of its expedited installation of AMI meters.

Adjustment related to the remaining useful life of legacy meters has been settled between DEP and the Public Staff, as set forth in the Agreement and Stipulation of Partial Settlement between DEP and the Public Staff filed in this proceeding on November 22, 2017.

Coal ash management costs. With regard to the deferred and proposed ongoing costs of DEP's coal ash management activities in this proceeding, I recommend the following adjustments:

First, flow-through of the adjustments recommended by other Public Staff witnesses; second, jurisdictional allocation of all coal ash expenditures by a comprehensive system factor; third, addition of a return on deferred coal ash expenditures from

September of 2017 through January 2018; fourth, calculation of the return between January 1, 2015, and January 31, 2018, using a mid-month cash flow convention; fifth, amortization of the balance of deferred coal ash expenditures after removal of other adjustments over a 26-year period beginning February 2018; sixth, reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base in order to make possible an equitable sharing of the cost; seventh, removal of the ongoing annual expense amount proposed by DEP.

Company Witness Bateman has indicated in her rebuttal testimony that DEP does not oppose adjustment numbers 3 and 4 listed above.

With regard to the first adjustment listed above, I have first removed the distinction between those costs the Company describes as CAMA-only and the remainder of the coal ash costs. For those CAMA-only costs, the company has utilized North Carolina retail allocation factors that do not allocate any of the system-level costs to South Carolina retail operations. However, the Public Staff believes that even though some of the costs incurred by DEP are being incurred pursuant to North Carolina law, it is still fair and reasonable to allocate those costs to the entire system. Second, I have used the energy allocation factor to allocate system-level costs -- coal ash costs to North Carolina retail operations, rather than the demand-related production plant allocation factor utilized by the Company.

With regard to the amortization of deferred coal ash costs and the removal of the unamortized of those costs from rate base, the Company has recommended an amortization period of five years with the unamortized balance included in rate base. In the opinion of the Public Staff, the five-year amortization period proposed by the Company is simply too short for the costs of the magnitude and nature of these. Instead, the Public Staff has been guided in its choice of amortization period by its belief that it is most reasonable and appropriate for DEP's coal ash costs, even after specific and prudently-incurred or otherwise unreasonable amounts have been discovered and disallowed for recovery, to be shared equitably between the ratepayers and the Company's shareholders.

There are two general reasons why such sharing of costs for coal ash management is reasonable and appropriate for ratemaking purposes. First, discussed in more detail by Public Staff Witness Lucas, the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments in violation of state and federal laws supports ratemaking that assigns a large share of the costs for DEP shareholders to pay. Second, there is precedent for approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. Such sharing between ratepayers and shareholders has been approved for costs of abandoned nuclear construction and for environmental cleanup of manufactured gas plant facilities.

The first step in achieving a sharing is to remove the unamortized amount of the deferred expenses from rate base. As a result of taking this step, the Company will not be allowed to earn a return from the ratepayers on the unamortized balance while the deferred costs are being amortized. The second step is to choose an amortization period that will result in a reasonable and appropriate sharing of the costs. In this proceeding, as stated in my supplemental testimony, the Public Staff recommends an amortization period of 26 years, beginning on the date the rates approved in this proceeding become effective. Based on the net of tax overall rate of return agreed to by DEP and the Public Staff in the stipulation, a 26-year amortization period results in the ratepayers bearing approximately 50 percent of the present value of the January 2015 through August 2017 deferred costs at February 1, 2018, with a return accrued to that point. It should be noted that the amortization period chosen to achieve a given level of sharing will change as the net-of-tax rate of return changes. The Commission has taken the sharing approach several times in past cases, most often in the cases of nuclear and coal plants abandoned prior to commencing commercial operation. The Commission's approach has also been upheld by the North Carolina courts, including the North Carolina Supreme Court. DEP's accrued coal ash management costs may qualify as regulatory assets, but they are not a utility plant. The Commission is under no legal obligation to include them in rate base or to otherwise allow a return on them to be recovered or accrued.

In the recent Dominion North Carolina Power general rate case, the Public Staff agreed to an amortization period of five years for coal ash costs, with the unamortized balance included in rate base. However, the Public Staff considers the facts and circumstances of this case to be quite different, including the sheer magnitude of DEP's costs in comparison to DNCP's.

In my testimony, I describe the Public Staff's recommendation regarding the amortization of deferred coal ash expenditure as being for provisional cost recovery. I use the term "provisional" because there are certain incurred expenditures for which the appropriateness of recovery may depend on the outcome of lawsuits or regulatory reviews. It is possible that the outcome of these legal situations could demonstrate the sum of the deferred expenditures were either imprudently incurred or otherwise unreasonable or inappropriate for recovery. If that proves to be the case, the Public Staff will propose an appropriate adjustment in DEP's next general rate case.

With regard to the proposal by DEP for an ongoing annual expense amount, or run rate, and an ongoing regulatory asset/liability to capture unrecovered prudently incurred and reasonable coal ash costs incurred after August 31, 2017, the Public Staff agrees with the proposal for an ongoing regulatory asset/liability that opposes the establishment of a run rate. The main reason for the Public Staff's

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opposition is that it would potentially make future equitable sharing of the costs of coal ash costs much harder to achieve. The Public Staff recommends that no ongoing recovery of annual future costs be allowed. Instead, such costs should be deferred for consideration of amortization in the Company's next general rate case. The Public Staff does recommend that the accrual of a return on future deferrals between rate cases be allowed by the Commission.

2016 storm costs. On December 16, 2016, in Docket Number E-2, Sub 1131, DEP filed a petition with the Commission requesting deferral accounting treatment of its costs incurred due to its 2016 storms. Specifically, DEP requested authorization to defer the incremental North Carolina retail operations and maintenance expenses, depreciation expense on capital investments, return on undepreciated capital costs, and carrying costs incurred in relation to the 2016 storms, reduced by the $12.7 million in normalized storm expenses approved in its Sub 1023 general rate case. In its March 15, 2017, initial comments in the docket, the Public Staff recommended that the Company only be allowed to defer the difference between its actual incremental O&M expenses related to 2016 storm costs and a normal amount of $27.4 million. The Public Staff also recommended that no deferral of deprecation expense, return on undepreciated capital costs, or carrying costs be allowed. Finally, the Public Staff recommended that DEP be required to amortize the deferred costs over a 10-year period beginning in October 2016.

The Public Staff believes that the position it took in its initial comments filed in Sub 1131 continues to be appropriate and reasonable. The reasons for that position are set forth in the initial comments, which are attached to my testimony as Maness Exhibit 3. A summary of these reasons is as follows:

Number one, merely because the storm costs incurred in a given year are greater than $12.7 million, it cannot simply be assumed that the larger expense is extraordinary. Instead, in this particular case, because the actual storm expenses included in the 10-year average used in Sub 1023 normalization spanned a wide range of annual amounts, from one annual amount as low as $1.8 million to one as high as $27.2 million, and because, in the 14-year period from 2002 through 2015, the Company incurred storm costs ranging between $22.9 million and

$27.4 million in five years, the Public Staff believes that, at least $27.4 million of the 2016 North Carolina retail storm expenses, should be considered normal for purposes of the Company's deferral request.

Number two, given the large size of the deferral recommended in this case, the Public Staff recommends that the deferred cost approved by the Commission be amortized for regulatory accounting purposes over a 10-year period.

Number three, it has been the historical practice of the Commission to begin the amortization of single storm deferrals in the month the storm occurs. Therefore, the Public Staff recommends that the amortization be required to begin no later than October 2016.

And number four, the Public Staff is not aware of any Commission precedent supporting deferral of depreciation expense and associated carrying costs resulting from storm damage. Therefore, the Public Staff believes that the Commission should continue its past practice.

The Company presented certain investor reporting-related accounting guidance to support delaying the beginning of the amortization of the deferred storm costs until this case. However, I do not believe it is appropriate for the Financial Accounting Standards Board or the Company's external financial statement auditors to control the Commission's decisions with regard to regulatory accounting or ratemaking purposes. It is the Public Staff's opinion that, for storm costs, and, in general, other events that cause fluctuations in utility income between rate cases, is most appropriate and reasonable for the Company to begin amortizing deferred costs into cost of service immediately. The purpose of deferral accounting is not to preserve costs for an indefinite period of time.

Additionally, in my testimony, I discuss the treatment of new wholesale load resulting from the Company's 2015 acquisition of generation familiarities from the North Carolina Eastern Municipal Power Agency and how the transfer of that benefit to base rates should affect the Joint Agency Asset Rider. The Public Staff and DEP are in agreement regarding this matter.

This completes my summary.

MR. DROOZ: The witnesses are available for cross examination.

CHAIRMAN FINLEY: Cross examination from

the east side of the room?

CROSS EXAMINATION BY MR. PAGE:

Q. I have just a few, and they are predominantly -- Mr. Lucas, I'm sorry -- directed towards Mr. Maness. But just as I have done with prior panels, Mr. Lucas, if I ask a question of Mr. Maness and you have something to contribute, please feel free to do so.

Good afternoon, Mr. Maness.

A. (Michael Maness) Good afternoon.

Q. I wanted to look first -- and it's nice that you have the summary, because it helps me focus where I want to get. So if you look at page 2 of that, the end of the second full paragraph where you are saying, essentially, are you not, that you used the energy allocation factor to allocate system-level coal ash costs to North Carolina retail operations?

A. Yes, sir.

Q. So what you are saying there is, at some point in time, the Commission would have made a decision from among the competing figures, the figures that Duke says are appropriate for collection in toto, and those that the Public Staff and other parties say are correct to allow Duke to put into rates, and when that figure is arrived -- and that, of course, has to be allocated by some methodology; is that correct?

A. Yes, that's correct.

Q. And the methodology that you have chosen is the per kWh or energy methodology, correct?

A. Yes, sir.

Q. Now, there are other allocation methodologies that could be used to make that allocation; are there not?

A. Yes, there are.

Q. For example, the Company has used one of those. It has used the demand, or asset allocation methodology, the 1CP?

A. Yes. I think the Company typically refers to that as the production plant allocation factor, but it is based on demand in their proposal.

Q. And that's an allocation factor that's also used with some frequency, particularly in general rate cases, to allocate the rate base from one customer class to another?

A. It is. There are different methodologies for calculating that factor. One, which is what the Company is using in this case, is based on -- purely on demand. I'm not a cost-of-service allocation expert, but there are several others, including one that's based on measurements of both demand and energy.

Q. All right, sir. And there is, yet, a third methodology for allocating cost related to consumption of a fuel, such as the methodology that's used in the annual fuel adjustment rider for Duke progress; is that correct?

A. That's correct. Now, that is very closely related to the energy factor that's used in the general rate case. In some instances -- and I can't remember the details sitting here on the stand. In some instances, those costs can be allocated by energy use at the meter, whereas, in the general rate case, we are really talking about energy use as rolled up to the generating level. In other words, adding back the losses between the meter and the generator.

Q. Specifically as to the cost allocation factor that has been used recently in the DEP annual fuel adjustments, it's an equal percentage allocation methodology; is it not?

A. Well, I look at that equal percentage allocation methodology as sort of an adder. It doesn't really have to do with principles necessarily of cost allocation, but it is a step that the Commission has taken in its ratemaking for fuel costs that basically equalizes, as you say, the increase across customer classes.

Q. But that amount, that methodology, the equal percentage, that's a result of negotiations between Duke, and the Public Staff, and the other rate-paying stakeholders; is it not?

A. I believe that's correct. I believe that those were -- that was a negotiated procedure.

Q. Is it correct for me to say that, of all of these methodologies we have discussed, the one which results in the allocation of the least amount of cost to the residential customers and the greatest amount of cost to the high-load factor manufacturing customers is the method you have chosen, the energy allocation; am I correct in saying that?

A. I usually do not testify on allocations between customer classes. In the accounting division, we usually are more concerned with jurisdictional allocations. So I can't say that that is correct in detail. I do have some general understanding that it can, at times, result in a higher allocation to high-load factor users.

Q. Yeah. Any time you allocate a cost on kWh energy consumption, that tends to hit the folks with fewer meters but a whole lot of monthly purchases, such as industrial customers?

A. I believe that that is generally correct. I would point out, however, that there are some, I don't know if you would call them anomalies, but in talking about allocation methodologies, in general, for example, the difference between the summer CP method and the summer/winter peak and average method, we have had at least one rate case in recent years when using the summer/winter peak and average method actually worked out, at least from a jurisdictional basis, to be a lower overall increase -- or a higher overall increase than the summer CP method, but I'm not sure how that was reflected in the customer classes.

Q. Suffice it to say, Mr. Maness, that the Staff is not recommending that the ultimate coal ash cleanup costs that are determined to be fair and reasonable by the Commission for inclusion in the rates in this case -- you are not recommending that those be allocated on the SWPA method, are you?

A. No, we are not.

Q. All right. Can I turn, then, with you over to page 3 near the bottom of your summary where you are

talking about the amortization period of 26 years?
A. Yes.
Q. Have you been present in the courtroom during most of the preceding days of hearing?
A. No. Actually, I have not. Since the early days of the hearing, I have not been here much of the time.
Q. All right. Have you heard testimony to the effect that Duke has been generating with coal to produce electricity since the 1920s?
A. Yes.
Q. And that's a period of almost 100 years?
A. Yes.
Q. And never before, until the recent changes in the CCR rules and the North Carolina CAMA legislation, has it been necessary for Duke to come in and file for a significant cost item dealing with coal ash cleanup; this is the first time it's happened, isn't it?
A. Certainly nothing this significant. The Company did include in its last rate case a smaller amount related to the disposal of coal ash as it perceived it before the CCR rule and CAMA 2014 were put into place.
Q. All right. One could make the argument,

could one not, that a proper amortization period would be the same length of time that it took to develop all of these coal ash deposits?

A. One could argue that. That is not the basis of our recommendation, and I don't think we really considered that as a possible amortization period during our investigation.

Q. In fact, yours is only about a fourth of that long; is that correct?

A. If you are talking about 100 years; yes, sir.

MR. PAGE: Thank you. That's all I have.

CHAIRMAN FINLEY: Mr. West.

CROSS EXAMINATION BY MR. WEST:

Q. Good afternoon. I'm James West from the Fayetteville Public Works Commission.

A. (Michael Maness) Good afternoon.

Q. I have a few questions for Mr. Maness. Mr. Maness, I would like to direct you to the last paragraph on page 4 of your summary where you talk about deferring coal ash expenditures and provisional cost recovery.

A. Yes, sir.

Q. Specifically, you mentioned that the cost recovery would be provisional because it, quote, may depend upon the outcome of lawsuits or regulatory reviews?

A. Yes.

Q. On page 25 of your testimony, between the lines 11 and 18, you mention that there is some insurance litigation that is pending.

Are the lawsuits that are relevant to the provisional cost recovery -- excuse me. Is the insurance litigation included in the lawsuits that you believe are relevant to the provisional cost recovery?

A. Could you repeat that question, please? I wasn't sure I understood it.

Q. Is the insurance litigation referenced on page 25 of your testimony included in the lawsuits that are relevant to the provisional cost recovery that you mentioned in the last paragraph of page 4 of your summary?

A. No, not directly, but we would certainly maintain that any recoveries related to insurance that the Company obtains should be offset against the total amount of reasonable and appropriate coal ash costs that the Commission approves it recover.

Q. Were you present when Mr. Fountain was cross examined by the Attorney General in the second day of the hearing?

A. Yes.

Q. If, hypothetically, Duke was found to have missed the statute of limitations, and therefore rendered itself ineligible for tens of millions of dollars of insurance coverage, do you believe that that should be relevant to the provisional cost recovery?

A. I believe that, if it was found that that was the case, that it would be appropriate for the Public Staff and the Commission to investigate whether Duke took all prudent steps to maximize its insurance recoveries.

Q. And if Duke failed to do so, how would you propose that that be remedied?

A. That's really, I think, asking me to speculate on what a future ratemaking treatment might be. One possibility, however, would be to look at what the likely insurance recovery would be if, in fact, Duke had taken prudent steps. That becomes a little bit difficult, because then you are basically, sort of, hypothesizing what the outcome of litigation that didn't take place might be, but that would be, at least, something that we could consider, but there might well be other potential solutions to that.

Q. That's what I am trying to get at, though. If there was a conclusion on the part of the Public Staff or the Commission that Duke had committed malpractice, in the sense that they had missed the statute of limitations or done something else that damaged their insurance coverage claims, first, could we include that in the provisional cost recovery, as you have proposed it?

A. Are you saying, as an offset -- some sort of offset to the cost to be recovered; is that what you mean --

Q. Correct.

A. -- by included? Conceptually, I think you could have an investigation to determine if that should be. The challenge would be in determining the amount. It's certainly a challenge -- that's certainly a challenge we would be willing to face and examine, but I think -- I don't think it would be appropriate for me to speculate at this point as to exactly how that would be done.

Q. Well, I'm not worried about the amount. I'm just asking about the -- you're the accountant for the Public Staff. I'm asking about how cost recovery would be addressed.

If we didn't use this provisional cost recovery mechanism to which you referred in your testimony, how would you propose that an instance of malpractice be addressed from a rate perspective?

MR. DROOZ: Asked and answered.

CHAIRMAN FINLEY: Overruled.

THE WITNESS: I think, in a -- in general, I think that, in a future general rate case, when more is known about the outcome of the insurance litigation, then the Public Staff or another intervenor could bring before the Commission how it thinks that any failing that it believes had occurred on Duke's part should be addressed and potentially offsetting the amount of coal ash costs that should be recovered over the long run.

BY MR. WEST:

Q. Meaning that would apply to an existing deferred account, correct?

A. Well, I think that -- and our proposal in this case, basically, is we are going to have this deferral that's related to the costs that have been incurred through August 2017. In the next general rate case, we will be looking at the costs incurred from December 2017 until -- until some time close to the date that those rates in the future rate case would go into effect. And whatever the so-called facts on the ground are at that point, we would probably look at how they should be treated with regard to those costs incurred in that time period.

When I was talking in my testimony about the provisional cost recovery, I'm basically talking about costs that have already been incurred, and whether, as the result of future litigation, it might appear that those costs should not be included in the amount that is shared, but maybe should be directly disallowed.

Q. Are you familiar with the concept of retroactive ratemaking?

A. Yes.

Q. Is there any concern that, if the Commission were to fail to address the insurance litigation in this case, that they may have to address the issue of retroactive ratemaking in the next rate case?

A. First of all, I don't want to stray too far into the grounds -- into legal grounds in determining what is and what is not retroactive ratemaking. From an accounting ratemaking standpoint, I believe that if the Commission wishes to determine in a general rate case that the recovery of certain costs that it approves in rates in that case is provisional, I believe that it can do so. Now, whether -- and Counsel has not disagreed with me on that. But as far as making any further comment, I think it would have to be made as a legal matter.

Q. Would it be your position that the future deferred accounts, to which you were referring earlier in your testimony, would also need to be made provisional in order for that to work?

A. I think that would depend on the facts and circumstances in that particular case with regard to, say, if most of the litigation is already over, then perhaps you would not have to continue the provisional requirement, but if it wasn't already over, then there might be some need to do so.

MR. WEST: All right. I don't have any further questions.

CHAIRMAN FINLEY: Who is next? Mr. O'Donnell.

MR. O'DONNELL: Thank you, sir.

CROSS EXAMINATION BY MR. O'DONNELL:

Q. Mr. Maness, I'm sure you would agree that coal is a fuel, it has energy potential, and that ash is not a fuel, it has no energy potential?

A. That's correct. It's the residual of coal, not the initial coal pre-burn, but it's what is left over from the coal after the burn.

Q. And what you are -- is it your rationale, if I could state this sort of crudely, that coal is energy related, ash is coal related, therefore ash is energy?

A. I think that's a good, to use your word, crude description.

Q. Okay. But accurate?

A. Generally so, yes.

Q. All right. And coal, as a fuel, is recoverable through the fuel clause, is it not, the cost of coal?

A. The cost of burning --

Q. Let me rephrase it. I'm sorry. I don't mean to interrupt you.

A. All right.

Q. Cost of coal burned is recoverable through the fuel clause?

A. The cost of coal burned and the cost of transporting the coal is recoverable through the fuel clause, yes.

Q. And leaving out beneficial reuse, which is a small piece, the cost of ash remediation is not recoverable through the fuel clause, is it?

A. Excluding the dispute over beneficial reuse, I would agree.

Q. All right. And does passing coal -- excuse me. Let me rephrase that.

When Mr. Page asked you about the equal percentage method of, we will call it allocating fuel costs to the customer classes, that results in each class paying an equal percentage increase in its total rates, including fuel; does it not?

A. Yes. I think that's generally correct, but I do want to reiterate, what I said is that I don't look at the equal percentage method as rising to the level of what we would call an allocation methodology like the summer CP or the summer/winter peak and average. I think it was a negotiated and then approved by the Commission ratemaking arrangement to -- that wasn't necessarily based on cost causation.

Q. But wouldn't today's customers who paid for burned coal through the fuel clause be paying less per unit than today's industrial customers who were allocated the cost of ash on an energy allocator?

A. I'm sorry, could you repeat that? I didn't quite follow it.

Q. I will try. I sort of confused myself.

Isn't it true that today's industrial customers, who pay for the cost of fuel burn through the fuel clause and are allocated their share on an equal percentage basis, are paying less of the total cost than today's -- than you would have today's industrial customers pay by allocating of total coal ash remediation than they would pay as you would have them allocated on an energy allocator?

A. I'm afraid that I'm gonna have to decline to answer your question, just because I -- I think it might depend on particular facts and circumstances, and even so, it's a complicated enough question that I think I would need to work out some examples to come up with an answer.

Q. Okay. Thank you, sir.

CHAIRMAN FINLEY: Anybody else. Duke?

MR. BURNETT: Thank you, Mr. Chairman.

CROSS EXAMINATION BY MR. BURNETT:

Q. Nice to meet you, Mr. Lucas, Mr. Maness.

Mr. Maness, I will not have any questions for you on your testimony at all today. They will all be on Mr. Lucas' testimony.

Mr. Lucas, you had your deposition taken in this matter on November 2nd of this year, correct?

A. (Jay Lucas) That's correct.

Q. And on page 58 of your deposition, line 14 through 20, you stated that the Company had not done a perfect job of managing its coal ash dams over time; isn't that right?

A. (Witness peruses document.)

Can I get those line numbers again, please?

Q. Sorry about that. It is page 58, lines 14 through 20.

A. (Witness peruses document.)

That's correct.

Q. Thanks. And I will just put them up on the screen there so that will be helpful, maybe finding that. But after you thought about that a little bit, you filed an errata sheet to your deposition and changed that to say that the Company didn't do a proper job, rather than perfect; isn't that right?

A. Let me find that as well.

(Witness peruses document.)

Q. And again, I have got that up on the screen, if that's helpful.

A. Okay. That's correct.

Q. Okay. And in all fairness to you, Mr. Lucas, between perfect and proper, that could be a matter of semantics, right?

A. It's a matter of degree too, or semantics.

Q. Okay. Now, on page 73, lines 8 through 10, of your deposition, you testified that you concluded in your analysis in this case that denying the Company cost recovery for all of its CAMA compliance costs was not an appropriate option; isn't that correct?

A. That's page 73. I'm sorry, give me the line numbers again.

Q. Yes, sir. 73, lines 8 through 10.

A. Okay. Okay. I understand.

(Witness peruses document.)

I have to back up, because there is a series of questions and answers here. I'm gonna have to --

(Witness peruses document.)

We were talking about the -- I was being asked about the Attorney General's position, and page 73, starting on line 8 asked the question about the Attorney General's position, and I come out and say that's not one of the positions that the Public Staff ultimately chose, and I say, "That's correct."

Q. Right. Right. And then, after you thought about that a little bit, you filed an errata sheet and you changed that "not appropriate" to "preferred option"; isn't that correct?
A. (Witness peruses document.)
That's correct.
Q. And on November 15th, you filed supplemental testimony in this matter; isn't that right?
A. That's correct.
Q. And in that supplemental testimony, you also changed some of the assertions that you made in your direct testimony; isn't that right?
A. That's correct.
Q. For example, in original Exhibit 5 to your direct testimony, you took the position that the Company has 2,172 NPDES permit violations over the past 10 years; isn't that right?
A. That's correct.
Q. And in your supplemental change -- in your supplemental testimony, you changed that assertion of 2,172 down to 458; isn't that right?
A. That's correct.
Q. And if I had my math correct, that's about a 79 percent reduction. Do you agree with that, subject

to check?

A. Yes.

Q. Now, of your remaining 458 alleged NPDES permit violations, you would agree with me that 255 of those are what are called failure-to-monitor violations; isn't that right?

A. That's correct. And those are -- fails-to-monitor is a violation of the permit.

Q. And those 255 failure-to-monitor events are reported on DEQ's BIMS, or Basin-Wide Information Management System; isn't that right?

A. That's correct. But I would need to clarify a little bit. When they reported their various types of frequency violations, some of them are considered to be a BIMS error, where somehow the computer system made an error in calculation, but there is a particular type, and that failure to monitor, those 255 violations are called facility-reporting error, and that's where DEQ considers the owner of the facility made a mistake in reporting.

Q. Exactly the next subject I wanted to talk to you about, Mr. Lucas. I appreciate you leading me there effortlessly.

MR. BURNETT: I would like to hand out

what I would like to mark as DEP Lucas Cross Exhibit Number 1, please.

CHAIRMAN FINLEY: We will mark this exhibit that is being passed out as DEP Lucas Cross Examination Exhibit Number 1.

(Whereupon, DEP Lucas Cross Examination Exhibit Number 1 marked for identification.)

BY MR. BURNETT:

Q. Has she handed you a copy?

A. Yes, she has.

Q. Okay. Now, I would like to turn over to page 28 of DEP Lucas Cross Exhibit 1. Let me know when you are there.

A. I'm there.

Q. Okay. And you see on page 28 of 39, there on the lower left-hand corner it says "monitoring violation"; isn't that right?

A. Yes.

Q. Okay. And it is undisputed that the word "violation" is used right there, correct?

A. Yeah, they used the word "violation."

Q. Okay. Now, if you go over on that same page 28 of this exhibit to the right-hand side, you see

"violation action," right?
A. That's correct.
Q. And I believe that's what you just told me about; isn't that right, Mr. Lucas? That's where those reporting action dispositions are listed?
A. That's correct.
Q. And if we look through Asheville, if we go several pages throughout all these monitoring violations, you will see that every one of them says "no action taken," and you will see BIMS reporting error, or something along those lines; isn't that right?
A. That's correct.
Q. And although the word "violation" is clearly used there, you would agree with me that the violation action disposition notation there shows that those are not really violations at all; isn't that true, Mr. Lucas?
A. Well, you are talking about specifically where they say BIMS calculation error, that's not a violation?
Q. Well, what I am saying is, for the Asheville site, under monitoring violations, which begins on page 28 of Cross Exhibit 1, if you were to look at

every one of those violation action entries on page 28, 29, and 30, you will see that every one of them say no action to some degree, and then it's followed by some designation; isn't that right?

A. (Witness peruses document.)

That's what I see here.

Q. Yes, sir. And, in fact, on your Revised Exhibit Lucas 5, if we look on the Asheville column, and that's up on the screen there, you will see that you also agree with my position there, because under "Asheville failure to monitor," you have the number zero; isn't that right?

A. That's correct.

Q. Okay. If you would go with me on this same DEP Lucas Cross Exhibit 1 to the first page, sir?

A. I'm there.

Q. You see this is a different category on the left-hand side that we are looking at there; this is called limit violations; isn't that right?

A. That's correct.

Q. And Mr. Lucas, the word "violation" is, again, clearly used there after the word "limit," correct?

A. That's correct.

Q. Much like we discussed before, we go over to that right-hand side where it's "violation action"; do you see that?

A. Yes.

Q. Now, there is one there that says "proceed to NOV"; do you see that, the very first one?

A. That's correct.

Q. And I have that correct that that means proceed to notice of violation; isn't that right?

A. That's correct.

Q. And you would agree with me that if you looked through this entire 39-page report for the Asheville site, you would only find one instance of "proceed to NOV"; isn't that right?

A. Subject to check. I don't see that anywhere else in these pages.

Q. Yes, sir. And let's go back to your Exhibit 5. In fact, if I look at your Revised Lucas Exhibit 5, you will see for the Asheville site that, out of all of the potential violations you list there, you list only one, which is consistent with the only one appearing on page 1 of Cross Exhibit 1; isn't that right?

A. That's correct.

Q. Okay.

MR. BURNETT: Now, let's hand out what I would like to mark as Lucas Cross Exhibit Number 2, please.

CHAIRMAN FINLEY: The exhibit being passed out now will be marked for identification as DEP Lucas Cross Examination Exhibit Number 2.

(Whereupon, DEP Lucas Cross Examination Exhibit Number 2 marked for identification.)

BY MR. BURNETT:

Q. Do you have a copy of that, Mr. Lucas?

A. I sure do.

Q. Now, what we have here is the BIMS report, similar to what we saw for the Asheville report, for the H.F. Lee station; isn't that right?

A. It doesn't say it on here, but I will take your word for it this is the H.F. Lee.

Q. Okay. Well, it should say on page 1 of 57 "Facility Lee Steam Electric Plant"; do you see that right there at the top?

A. Oh, yeah, I see it.

Q. Okay. Thank you, sir. Now, if we turn over to page 31 of Lucas Cross Deposition 2, which is this

Lee report, we see there the beginning of the monitoring violation sections, just like we saw for the Asheville.

A. I'm sorry. Say that page again, please.

Q. Yes, sir. Page 31 of 57.

A. Okay.

(Witness peruses document.)

Okay.

Q. And in that section there on page 31 we start, again, with the monitoring violations, just like we looked at at Asheville; would you agree with me?

A. I see, yes.

Q. Okay. And I have to turn several pages until I get to the end there, but you would agree with me there are multiple pages that you allege are monitoring violations on this report, correct?

A. That's correct.

Q. Okay. And in fact, you mentioned that what you consider a violation there is what is called facility reporting error. I think you just testified to that; isn't that right?

A. Yes.

Q. And if I look at your Revised Lucas Exhibit Number 5, I see that, under failure to monitor for that column, you have 116 violations listed; isn't that right?

A. That's correct.

Q. And again, you base that on the violation action code of facility reporting error, correct?

A. That's correct.

Q. Okay. Do you see there on page 32 of 57 of Cross Exhibit Number 2 the words that precede facility reporting action, reporting error on that BIMS report?

A. Yes.

Q. That set of words says no action, period; isn't that correct?

A. That's correct, but that doesn't mean it's not a violation.

Q. Okay. That is unlike the "proceed to NOV" notation that we saw on the Asheville, isn't it?

A. That's correct. And -- but I need to point out why this concerns me. A facility reporting error, we don't know, and DEQ doesn't know, what the results of that test would have been. It's just missing data, and we can't speculate what the problem was.

Q. Okay.

MR. BURNETT: I would like to hand out what I am going to now mark as DEP Lucas Cross

Exhibit Number 3.

CHAIRMAN FINLEY: All right. This January 22, 2013, letter shall be marked for identification as DEP Lucas Cross Examination Exhibit Number 3.

(Whereupon, DEP Lucas Cross Examination Exhibit Number 3 marked for identification.)

BY MR. BURNETT:

Q. Mr. Lucas, are you familiar with the type of document that I have handed you here?

A. I'm somewhat familiar with these.

Q. Okay. In your familiarity that you have, what is it?

A. (Witness peruses document.)

Discharge and monitoring report.

Q. Okay. And this is a report that the Company has to submit to the North Carolina regulators certifying that it's true under penalty of the law; isn't that right?

A. That is correct.

Q. And you will actually see that on the bottom of page 1 of Cross Exhibit 3, correct?

A. That's correct.

Q. If you turn to the second page of Cross Exhibit Number 3, you will see a diagram and a chart there; will you not?

A. That's correct.

Q. Okay. If you look under flow effluent daily return, you will see a lot of numbers in that column that have zero in there; wouldn't you agree?

A. I mean, a little bit. The column numbers -- you say flow effluent daily rate?

Q. Yes, sir.

A. Okay. Okay. I see that.

Q. And you will also see that several of the columns -- there is a global "no discharge this month" written across several columns, such as pH, suspended solids, and the like; do you see that?

A. I see that.

Q. Okay. You would agree with me that this monitoring that we are talking about at the basins monitors the outflow of water from the basin into another body of water; isn't that right?

A. That's correct.

Q. Okay. If there is no water flowing from the basin into the outflow and into the other body, would you agree with me that there is nothing to monitor?

A. Yes. But the Company still has to report to DEQ its results.

Q. That's right. I can't take a test tube and go on the basin side and say no water's coming out of the outflow, I will just take a dip into here and see what the results is; I have to have an outflow to measure an outflow; isn't that right?

A. That's correct.

Q. So you would agree with me that, if my outflow monitoring point was submerged under water because the other body of water on the other side of the basin had elevated, I can't monitor what the outflow is if that water is -- if that point is underwater, can I?

A. It depends on where the specific monitoring point is. It could happen if the end of the pipe is underwater that you couldn't take a sample.

Q. Okay. Well, I guess what I'm getting at here is, isn't it true that the facility monitoring errors that you take issue with, and allege are violations, are really instances where the Company had no outflow to monitor or problems with getting a valid sample, and that is, in fact, why the DEQ says no action taken on those?

A. I disagree. I mean, this -- the DEQ record says it's no action, facility reporting errors. The facility didn't report at all. These are DEQ's records. That's where I took my data from.

Q. Okay. You would agree with me with the fact that you made clear in your deposition that you're not an environmental regulator, right; you work for the Public Staff?

A. That's correct.

Q. And you also made clear that DEQ is in the best position to determine what violations are, not the Public Staff; isn't that right?

A. That's correct.

Q. Okay. Now, let's take a look at your original Exhibit 6 to your testimony.

In that original Exhibit 6, you claim that the Company has had 8,253 2L exceedances; isn't that right?

A. That's correct.

Q. And in your Revised Exhibit 6, you lower that number down to 3,008, don't you?

A. (Witness peruses document.)

In the Revised Lucas Exhibit Number 6, I split up the data. We looked deeper into the exceedances, and we found there were actually over 2,800 true violations of groundwater standards.

Q. I see. But Mr. Lucas, you would agree with me that, on your original Exhibit 6, your total line says 8,253, and on your Revised Exhibit 6, which both purport to reflect 2L exceedances, your total is 3,008? I will certainly accept it if you want to say your total is really 2,800 rather than 3,008.

A. In the original exhibit I filed on October 20th I point out over 8,000 exceedances, but exceedances aren't necessarily violations. We took a closer look and tried to determine what were true violations of groundwater standards. So it is true that there are over 3,000 exceedances, but to be more clear, there are over 2,800 violations.

Q. I don't think I could agree with you more, Mr. Lucas, that exceedances are not necessarily violations.

In fact, between your Lucas Exhibit Number 6 and your Revised Lucas Exhibit Number 6, you change your exceedance numbers for arsenic, boron, chloride, chromium, hexavalent chromium, cobalt, iron, manganese, pH, total dissolved solids, radium, and vanadium; isn't that right?

A. Subject to check. I see the general direction you are going. We thought it was more applicable, since exceedances are not necessarily violations and might not necessarily require Company action, we thought it would be more accurate to go out and point to true violations which do require Company action to correct.

Q. You would agree with me that the changes that you made in Exhibit 5 and Supplemental Exhibit 5, Exhibit 6 and Supplemental Exhibit 6 to your testimony came at a point in time after Company Witness Jim Wells filed his rebuttal testimony; isn't that right?

A. That's correct.

Q. Mr. Lucas, you agree with me that, in your testimony, you propose three categories of disallowances related to coal ash cost in addition to the disallowances recommended by witnesses Garrett and Moore; isn't that right?

A. I guess I have three general categories.

Q. And you also support what you have called an equitable sharing paradigm that Witness Maness then takes and implements; isn't that right?

A. That's correct.

Q. So if I add your three proposed disallowances of -- three proposed categories of disallowances with your support for the equitable sharing, just mathematically so we could talk about them principally, we could say you have your general proposed disallowances; would that be fair?

A. Yeah.

Q. I'm not trying to trick you.

A. No, no, no.

Q. I just want to talk one, two, three, four about these.

A. I'm just trying to -- I just want to answer your question well. On my testimony on page 62, beginning on line 14, I say, "In particular, Public Staff recommends the following expenditures be excluded from rate recovery," and I talk about litigation costs, and settlement payments, costs to remedy environmental violations were the costs exceed CAMA, and costs required to be excluded under probation conditions of the federal plea agreement, and you're right, there is a fourth general category where I recommend equitable sharing in the previous paragraph.

Q. Okay. Now, let's talk about your first proposed disallowance category, which I think you just said is disallowance of litigation cost and settlement payments in cases where there are environmental violations alleged.

Under this first category, Mr. Lucas, you propose that the Company be disallowed legal and settlement costs in cases where the party suing the Company alleges that the Company has violated an environmental law, and then where the Company later settles that claim without admitting any fault; isn't that right?

A. Either that or where the Company was fined.

Q. Okay. And with -- in an instance where the Company settles without admitting any fault, you recommend disallowances of those costs because you believe that, if the Company did not commit the violations being filed against it, the Company should not enter into the settlement agreement; isn't that right?

A. I believe the amount of the settlements -- the Company agreed to these large settlements because the Company believed it had some fault. It wasn't completely blameless, so it settled for millions of dollars in some cases.

Q. But as you said on page 65, lines 3 through 4 of your testimony, you're pretty clear to say, if DEP did not commit the violations, it should have not made those settlement payments; isn't that right?

A. That's correct.

Q. So based on your position, do you believe that, if someone sues Duke Energy Progress and the Company did not do anything wrong, that we should fight to the bitter end, no matter what the cost or consequences?

A. No. I make my basis on the size of the settlements.

Q. It would depend on the facts and circumstance of each case; wouldn't it, Mr. Lucas?

A. It depends on the facts, but a lot of the cases we are talking about, they had settlements. There wasn't a conclusion sometimes for various reasons, sometimes CAMA met the requirements of the plaintiffs, so the cases weren't pursued, but in other cases there were settlements.

Q. Mr. Lucas, it's fair to say that you may not have the best perspective on how to evaluate whether to litigate or set a lawsuit, because you don't do that as part of your typical job functions; is that right?

A. I don't do that, but I made my decision on just the large amount -- the millions of dollars of settlements were paid by the Company, and I don't believe the Company would have made those large settlement sums unless it believed it did have some fault.

Q. Isn't it fair, Mr. Lucas, that, again, you may not have the best perspective on how to evaluate whether to litigate or settle a lawsuit because you've never performed such an analysis until you attempted to do so in this case?

A. I'm sorry, say that question again, please.

Q. Yes, sir. It's fair to say that you may not have the best perspective on how to evaluate whether to litigate or settle a lawsuit because you've never performed such an analysis like that until this case; isn't that right?

A. That's correct.

Q. Okay. And while we lawyers don't do everything well, you would agree with me that, as a general matter, we are probably better at evaluating litigation settlements than non-lawyers; you would agree with that?

A. I can't agree. I -- like I keep saying, the large amount of these settlements -- I mean, me, as an engineer, I can see many millions of dollars the

Company had to pay out. Just, I think the Company would not have done it. It wouldn't pay out millions of dollars for no reasons. It paid out millions of dollars to settle these cases because it had culpability. It had responsibility for the environment violations that it created.

Q. I wish you would have said yes, you agree with me. It makes me feel like I may have wasted money for those three years of law school, Mr. Lucas.

Let me move on to your second recommended category of cost disallowances.

CHAIRMAN FINLEY: Mr. Burnett, if it's all right with you, we will pick up that line of questioning in the morning at 9:30.

MR. BURNETT: Yes, sir.

(The hearing was adjourned at 4:57 p.m. and set to reconvene at 9:30 a.m. on Wednesday, December 6, 2017.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appears in the foregoing hearing were duly sworn; that the testimony of said witnesses was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to this; and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 9th day of December, 2017.

NDTCA Electronic Transcript

JOANN BUNZE, RPR
Notary Public #200707300112

PLACE: Dobbs Building
Raleigh, North Carolina

DATE: Wednesday, December 6, 2017

TIME: 2:15 p.m. - 4:57 p.m.

DOCKET NO: E-2, Sub 1142

BEFORE: Chairman Edward S. Finley, Jr., Presiding
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

DUKE ENERGY PROGRESS, LLC

Application for Adjustment of Rates and Charges
Applicable to Electric Utility Service
in North Carolina

VOLUME: 20

Noteworthy
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P R O C E E D I N G S:

CHAIRMAN FINLEY: All right. Let's go back on the record, Mr. Ledford.

MR. LEDFORD: I have nothing further, Mr. Chairman.

CHAIRMAN FINLEY: Anyone else have questions for Mr. Floyd?

MR. SMITH: I have got some questions.

CHAIRMAN FINLEY: All right, Mr. Smith.

JACK FLOYD,

having previously been duly sworn, was examined and testified as follows:

CROSS EXAMINATION BY MR. SMITH:

Q. Good afternoon, Mr. Floyd. My name is Kyle Smith. I'm with the United States Department of Defense and all other federal executive agencies, and I am going to ask you a little bit about the summer coincident peak and the use of the 1CP methodology.

You recognize that DEP's system peak in the test year occurred in the winter, I believe it was January 19th of 2016, correct?

A. That's correct.

Q. And you are aware that DEP has consistently been a weaker -- a winter-peaking utility since 2013?

A. It looks to be trending that way, yes.

Q. And, in fact, it has had its peak in the winter since 2013; is that correct?

A. Subject to check, yes.

Q. And are you aware that DEP -- DEP's 15-year projection indicates it will be a winter-peaking utility for the foreseeable future?

A. Yes, I am.

Q. And, in fact, DEP projects every year it will have its peak in the winter until 2032; is that correct?

A. Subject to check, yes.

Q. And you testify on page 7, line 16 of your testimony that the Company's last two IRPs have placed more emphasis on the winter peak for planning purposes, correct?

A. Yes.

Q. Are you aware of the effect of using the winter peak rather than the summer peak in a 1CP cost allocation on the allocations to the rate classes?

A. Yes, I am. They tend -- the winter peak tends to shift more revenue responsibility to the lower-load factor customer classes.

Q. So is it correct that it would shift costs away from the LGS rate class?

A. Like I said, higher-load factor customers, yes, it would shift away from them towards the more lower-low factor, but it depends on when the class actually peaks.

Q. Okay. You support using the summer peak through this rate case; is that correct?

A. Well, we support the cost of service, as provided by the Company, for this proceeding only. There is no bones about it, the Public Staff has advocated a summer/winter peak and average method per cost of service. But in this case, the differences between those two methods were immaterial.

Q. Is that what you meant when you said that you would support it for this case only, it was between the 1CP methodology and the summer/winter peak and average?

A. For this case only. We are not contesting the cost of service provided by the Company, which is based on the summer CP.

Q. Would you support using a winter peak in the next rate case if DEP's projections hold true under 1CP methodology?

A. We would have to look at that, but we would not -- we would not typically support a coincident-peak-only method, whether it's the winter or the summer, a 2CP or a 12CP. The Public Staff has historically and continues to support cost of service methodology that it employs, both emphasis on the peak-demand component and the energy component, and, you know, every case that I worked on, that takes the form of the summer/winter peak and average method.

Q. Are you aware of the job retention rider proposed by DEP in this case?

A. I am, but I'm not the witness for it.

Q. I understand that. I want to ask you a few questions related to it, though.

That rider seems to create a subsidy to industry customers in the amount of approximately --

MR. PAGE: I object, Your Honor. He said he's not the witness to answer these questions.

CHAIRMAN FINLEY: Overruled. We have unlimited cross in this state. Go ahead.

BY MR. SMITH:

Q. All right. That rider seeks to create a subsidy to industrial customers in the amount of approximately $24 million a year, correct?

A. Yes.

Q. And that's paid for by an increase in the energy charge to all customers, correct?

A. That's the -- Mr. McLawhorn's testimony.

Q. So it would be paid for disproportionately by other large-energy users that don't qualify for it; is that correct?

A. It would be paid by all consumers of the utility, whether they are small users or large users. It would be paid on a proportionate amount per kWh.

Q. But those users that use a lot of electricity would pay more than those that use less?

A. The dollar amounts would be greater, yes.

Q. Has Staff looked at the benefit to the LGS class of using a winter peak as com -- and a 1CP methodology as compared to a benefit received by a subset of the LGS class with the JRR?

A. I have not, no.

Q. Is it correct that using a winter peak is an alternative to provide rate relief to industrial customers with high load factors that would -- without creating a subsidy for those customers?

A. I'm not sure I understand your question. The methodology for cost of service does not create subsidies or anything else with respect to what happens between classes. That is -- that is more of a rate design and a policy objective. Again, I think I said earlier, the cost of service is simply a snapshot of what happened in the test year for the Company.

Q. Right. So you agree that a JRR provides a subsidy, though?

A. It provides a discount. Whether or not you characterize it as a subsidy, that might be a different subject, but I can't do that. It is a rate discount, yes.

Q. And it's paid for by other customers?

A. It's paid for by the remaining ratepayer body, yes.

Q. And as you said, using a winter peak 1CP methodology wouldn't create a subsidy, correct?

A. Again, I'm not sure I understand what you're driving at when you say the winter CP creating a subsidy. The cost of service, itself, and the methodology, itself, I don't believe creates the subsidy. The meth -- we argue about methodology, but I don't believe that that, in and of itself, creates a subsidy. It's what you do with it, in terms of a job retention rider or any other rider, that could create that subsidy issue.

Q. And that's what I am trying to get at. A cost of service allocation methodology doesn't create a subsidy, right; it's just a methodology?

A. Again, I don't think that methodology, itself, creates the subsidy. It's purely a mathematical exercise. It depends on how you approach cost of service. The companies typically approach it on the basis of a single coincident peak, winter or summer. The Public Staff does not. We have advocated a peak demand and average approach to cost of service. So you might create a different subsidy, you might create a different revenue issue, return on rate base scenario, depending on how you approach that methodology.

Q. And if the Company chose to use a winter peak and a 1CP cost allocation methodology, that would reduce -- that would reduce the cost to high-load factor LGS customers?

A. It would. And it would also move that responsibility to the lower-load factor customers. From there, there has to be a policy question asked about whether or not the Commission wants to do that. That's why I say -- that is somewhat outside of cost of service. Do we want to move that type of responsibility to residential customers or do we not? That's a policy question that is beyond, I think, the scope of a cost of service.

Q. And residential customers would be paying for the rate discount, as you call it, or as I'm calling it, a subsidy through the JRR, correct?

A. They would pay that, yes. And I believe every other customer, including those that get the discount, would be paying it.

Q. Right.

MR. SMITH: That's all the questions I have.

CHAIRMAN FINLEY: Anyone else? Anyone else have cross examination for Mr. Floyd? Redirect?

REDIRECT EXAMINATION BY MS. FENNELL:

Q. One quick question, Mr. Floyd. Earlier we talked a lot about the basic customer charge, and I just want to clarify. You were not a participant in the settlement, but you have read the settlement, correct?

A. That is true.

Q. And you are aware that the stipulating parties have stated that they agree the basic customer charge was set at $14 a month?

A. The plain language of the stipulation, on page 13 and page 16, says that it is $14 a month and that we consider that to be just and reasonable.

MS. FENNELL: Thank you.

CHAIRMAN FINLEY: Questions by the Commission? Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Floyd, on page 9 of your direct testimony -- I'm going back to the discussion you had a minute ago about the cost of service methodology. You were asked on line 5, "Why are you not advocating the summer/winter peak and average methodology in this proceeding?" And you said in your answer, "In this proceeding, the differences between the per books calculations of revenue requirement between the summer coincident peak and the summer/winter peak and average methodologies is immaterial on a jurisdictional basis."

A. That's correct.

Q. And do I understand, "on a jurisdictional basis," you mean in terms of allocating the cost of services between the North Carolina retail rate requirement -- revenue requirement and the South Carolina --

A. That's correct.

Q. That's right. Well, what about on bases other than jurisdictional basis; is the difference material?

A. The -- I don't believe so. I anticipated your question.

Q. Thank you, sir. I like prepared answers.

A. The -- I did a comparison between the two methods early on in the case, just to see what was going on, and both on an NC retail jurisdictional basis and looking at other customer classes, primarily the residential, the numbers were not material, to me, enough to justify the time and effort of going through and supporting the peak and average method in this proceeding. Now, notwithstanding the Public Staff's history of supporting that, and we continue to support the use of the summer/winter peak and average method.

Q. Well, you did an analysis, and that's good. Did you put that analysis in the record?

A. I can provide you with this sheet of paper that does the comparison; yes, sir.

COMMISSIONER CLODFELTER: I --

Mr. Chairman, I would like to have that as a late-filed exhibit.

CHAIRMAN FINLEY: All right. We will request that of Public Staff as a late-filed exhibit.

BY COMMISSIONER CLODFELTER:

Q. And then I won't ask you what the difference actually was. I could look at the chart myself and read it.

A. Okay.

COMMISSIONER CLODFELTER: That's all.

CHAIRMAN FINLEY: Commissioner Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Floyd, just one question, and that is, the Company's proposed revenue increase, taking into account the changes agreed upon in the stipulation, do they adhere to the Public Staff's four principles in assigning the revenues per class?

A. That, as I understand, is a condition of the settlement, that they would adopt the principles that I have outlined in my direct testimony.

Q. But in your opinion, is each one of these four principles satisfied by the stipulation, the current stipulation?

A. As we sit here today, yes. It remains to be seen, once the revenue increase is ordered and how the Company prepares its rate schedules to satisfy that revenue increase, but I anticipate that that will be done in accordance with those four principles that I have outlined in the testimony.

Q. Does it cause you any concern if one or more of the principles aren't met, or do you still feel that the settlement is reasonable?

A. I do feel the settlement is reasonable, and I think I give you a little glimpse of that in the direct testimony where I say -- where I talk about the actual increase, the percentage of the increase versus the band of reasonableness for the return on rate base percentages. I think the percent increase takes a little precedent over the return numbers.

CHAIRMAN FINLEY: Questions on the Commission's questions? All right. Mr. Floyd, you may be excused.

We will accept exhibits and cross examination exhibits of Mr. Floyd. I think there were. We will accept the cross examination exhibits as well.

(Whereupon, Floyd Exhibit Number 1, NCJC et at. Floyd Cross Examination Exhibit

Numbers 1 and 2, and NCSEA Floyd Cross Examination Exhibit Number 1 were admitted into evidence.)

MR. ROBINSON: Mr. Chairman, before we move on to the next witness, we just have a brief housekeeping matter that we want to address.

CHAIRMAN FINLEY: Yes, sir.

MR. ROBINSON: Sure. So we just want to note to the Commission and the intervenors that this morning the Company filed a number of late-filed exhibits, as well as Simpson Redirect Exhibit 1, and we have some copies of those exhibits that we can pass out. Namely, the late-filed exhibits, briefly, 1 is the insurance policy information that was requested by Chairman Finley; Late-Filed Exhibit 2 was that coverage ratio information requested by Commissioner Clodfelter; Late-Filed Exhibit 3 is the Asheville ash reclamation contract also requested by Commissioner Clodfelter. We know with that late-filed exhibit there are two versions. There is a public and a confidential version. We have copies of both and we will pass out both the public and the confidential to those that have an

NDA with the Company. And then Late-Filed Exhibit 4 was the list of local and diversity-owned North Carolina contractors supporting the Company's ash basin work as requested by Commissioner Patterson. So we have some copies that we will pass out.

CHAIRMAN FINLEY: Pass those out and let people take a look at them, and we will have you move their admission.

(Whereupon, Late-Filed Exhibit Numbers 1 through 4 and Simpson Redirect Exhibit 1 were admitted into evidence.)

MR. RUNKLE: You also filed Late Exhibit 5.

MS. SOMERS: I believe that one may have been filed after -- we don't have copies of those yet, Mr. Runkle, but that was in response to Commissioner Brown-Bland's question around seeing the cost allocation of different methodologies. That may have been filed. I have not personally seen it yet, but it will be here shortly and we will hand out copies.

MR. RUNKLE: All right. Thank you.

MS. DOWNEY: Mr. Chairman, one housekeeping issue. Before we leave Public Staff's witnesses, just out of an abundance of caution -- I believe you've already done this, but I wanted to make sure that the testimony and exhibits of the Public Staff witnesses that were excused have been entered into the record: McCullar, Metz, Saillor, and Williamson.

CHAIRMAN FINLEY: They have been admitted, and we won't admit them again, but I think we have them covered.

MS. DOWNEY: Thank you.

CHAIRMAN FINLEY: And to this point, to the extent that I haven't admitted an exhibit that has been identified and not objected to, I will admit it.

(Whereupon, NCJC et al. Fountain Cross Examination Exhibit 1, Attorney General's Office Bateman Cross Exhibit Numbers 1 and 2, CIGFUR Wheeler/Hager Cross Examination Exhibit Number 4, NCJC et al. Hager/Wheeler Cross Examination Exhibit Numbers 1 through 7, NCSEA Wheeler/Hager Cross Examination Exhibit Number 1, and Supplemental Revised Lucas Exhibit Numbers 5 and 6 were admitted into evidence.)

MR. BURNETT: Mr. Chairman, Jon Kerin is on deck next for his rebuttal.

CHAIRMAN FINLEY: Come on up, Mr. Kerin. Mr. Kerin you have already been sworn.

THE WITNESS: Yes, sir.

JON KERIN,

having previously been duly sworn, was examined and testified as follows:

DIRECT REBUTTAL EXAMINATION BY MR. BURNETT:

Q. Good afternoon, Mr. Kerin. Are you the same Jon Kerin who filed direct testimony in this case?

A. Yes, I am.

Q. Did you also cause to be prefiled in this docket, on November 6th of this year, 27 pages of rebuttal testimony in question-and-answer form, and 5 exhibits consisting of 9 pages?

A. Yes, I did.

Q. Do you have any changes or corrections to that rebuttal testimony?

A. No, I do not.

Q. If I were to ask the same questions that appear in your rebuttal testimony today, would your answers be the same?

A. Yes, they would.

MR. BURNETT: Mr. Chairman, at this time, I would move that Mr. Kerin's rebuttal testimony be copied into the record as if given orally from the stand and that his five exhibits be marked for identification as prefiled.

CHAIRMAN FINLEY: Mr. Kerin's rebuttal testimony consisting of 27 pages is copied into the record as if given orally from the stand, and his five rebuttal exhibits are marked for identification as premarked in the file.

(Whereupon, Kerin Rebuttal Testimony Exhibit Numbers 1 through 5 marked for identification.)

(Whereupon, the prefiled rebuttal testimony of Jon Kerin was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**JON F. KERIN FOR**
For Adjustment of Rates and Charges	)	**DUKE ENERGY PROGRESS, LLC**
Applicable to Electric Service in North Carolina	)	

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, OCCUPATION, TITLE, AND BUSINESS ADDRESS.

A. My name is Jon F. Kerin. My business address is 400 South Tryon Street, Charlotte, North Carolina, 28202. I am employed by Duke Energy Business Services, LLC, as Vice President - Governance and Operations Support, Coal Combustion Products ("CCP").

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this rebuttal testimony on behalf of Duke Energy Progress, LLC ("DE Progress," or the "Company").

Q. ARE YOU THE SAME JON KERIN WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. PLEASE DISCUSS THE PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. The purpose of my rebuttal testimony is to address several issues discussed in the direct testimony of intervenors that are related to the recovery of costs associated with coal ash expenses. Specifically, I will address issues raised in the testimonies of Public Staff witnesses Garrett & Moore and Maness, and CUCA witness O'Donnell.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In total, Public Staff witnesses Garrett & Moore have conducted a robust analysis and investigation in the course of their engagement and I agree with a majority of their conclusions. Given the scope and magnitude of the information they had to investigate and the time in which they had to conduct their investigation, however, I believe that they did miss or overlook key facts in several of their recommendations that I will address specifically in my testimony. In summary, I don't believe that their suggested disallowances are warranted based on a complete view of the applicable facts.

As to CUCA witness O'Donnell, I do not believe that his analysis in which he recommends a 75% disallowance of DE Progress' costs is credible and I will outline multiple analytical flaws that are fatal to his conclusions.

II. RESPONSE TO GARRETT AND MOORE

Q. IN GENERAL, WHAT IS YOUR OVERALL IMPRESSION OF THE TESTIMONY THAT WITNESSES GARRETT AND MOORE FILED IN THIS MATTER?

A. Overall, I believe that witnesses Garrett and Moore ("G&M") conducted comprehensive research and analysis to arrive at their opinions in this matter and I agree with a large majority of their conclusions. G&M conducted and reviewed copious amounts of written discovery; set several meetings to discuss issues and questions with DE Progress representatives; and conducted site tours and inspections of DE Progress basins in reaching their conclusions. In my view, anyone offering substantive opinions in this matter on the propriety of DE Progress's coal combustion residual (CCR) compliance costs needed to conduct at least the same level of examination that G&M did to have a valid opinion on the reasonableness and prudency of those costs, but G&M were the only ones that I saw do this.

Q. DOES THIS MEAN THAT YOU ACCEPT THE DISALLOWANCES THAT G&M HAVE SUGGESTED BE MADE TO THE CCR COSTS THAT DE PROGRESS IS SEEKING?

A. No, it does not. I disagree with the disallowances that G&M have suggested be made. I disagree with G&M's recommended disallowances because I believe that they missed several key facts and sets of information and not because I believe that they did not conduct a thorough and principled analysis. As G&M notes in their testimony, the amount of data and information that they were asked to review in this case is overwhelmingly large and complex. It is not surprising that someone who has not lived with this company-specific subject matter every day for almost the past four years would miss some facts and information in conducting such a broad analysis, and in my testimony here, I have attempted to outline the facts and information that I think G&M may have fairly missed in offering their opinions.

Q. WHAT AREAS IN THE G&M TESTIMONY WOULD YOU LIKE TO ADDRESS?

A. First, I disagree with G&M's conclusion that an onsite landfill could have been built at the Sutton site in lieu of the arrangement that DE Progress has with Charah, Inc. to transport CCRs to the Brickhaven Mine when ash first started being moved from the site and the associated $80.5 million suggested disallowance that results from that conclusion. I also disagree with G&M's conclusion that an onsite landfill could have been built at the Asheville site in lieu of the arrangement that DE Progress has with Waste Management, Inc. to transport CCRs to an offsite location and the associated $45.6 million suggested disallowance that results from that conclusion. Finally, G&M make several observations regarding the potential for costs to be imprudent in the future should certain conditions arise (such as fulfilment fees, water treatment costs, beneficiation schedules, and beneficiation contract issues). While G&M are not suggesting disallowances for any of these potential future costs, I will address each of the concerns that they raise.

Q. WHY DO YOU DISAGREE WITH THE CONCLUSION THAT DE PROGRESS SHOULD HAVE BUILT AN ONSITE LANDFILL AT THE SUTTON SITE INSTEAD OF TRANSPORTING CCRs TO THE BRICKHAVEN MINE UNDER A CONTRACT WITH CHARAH, INC. WHEN ASH WAS FIRST BEING MOVED FROM THE SUTTON SITE?

A. My first area of disagreement involves DE Progress's ability to practically and, in compliance with CAMA, build an onsite landfill at the Sutton site under the timeframes that G&M suggest. Keep in mind that DE Progress has built an on-site landfill at Sutton and ash is being moved to that landfill today. Thus, I take no issue with the suggestion that an on-site landfill is a good choice for Sutton. Instead, I take issue with the timing of that decision in the

G&M analysis. While we agree with G&M that CAMA Part III, Section 5.(a) discusses the intended purpose of the CCR landfill moratorium, by its terms, the definition of "coal combustion residuals landfill," as stated in CAMA Section 3.(d), extended the moratorium for construction of a new CCR landfills over any facility, that "was" a wet ash pond. CAMA Section 3.(d) provides as follows:

> "... where the landfill is located wholly or partly on top of a facility that is or ***was***, being used for the disposal or storage of such combustions products, including, but not limited to, landfills, wet and dry ash ponds, and structural facilities."

In the case of the Asheville 1964 and 1982 ash basins, and the Sutton 1971 and 1984 ash basins, these are existing "wet ash ponds." While I am not a lawyer, nor am I an expert in legislation, it appears to me that if the General Assembly intended for the moratorium to have the limited applicability suggested by G&M, it would have certainly done so by including limiting language. For example, it could have drafted Section 5.(a) as follows:

> "... where the landfill is located wholly or partly on top of a facility that is or was ***(not applicable to any facility from which the coal combustion residuals were excavated and removed from the basin)***, being used for the disposal or storage of such combustions products, including, but not limited to, landfills, wet and dry ash ponds, and structural facilities."

The fact that the legislature did not include such language in the statute makes it clear to me that the existing Asheville and Sutton coal ash basins were subject to the CAMA moratorium for CCR landfill construction and, therefore, DE Progress was prohibited from constructing a coal combustion residuals landfill within the areas that were formerly used for the storage of coal combustion residuals.

Q. WERE THERE OTHER LIMITATIONS EXISTING IN 2014 AND 2015 REGARDING THE CONSTRUCTION OF CCR LANDFILLS IN THE FOOTPRINT OF AN EXISTING CCR SURFACE WATER IMPOUNDMENT?

A. Yes. Two additional regulatory limitations that I am aware of existed regarding the construction of a new CCR landfill on the footprint of an existing coal ash basin during this time period. These two limitations were both associated with the establishment of standards by NCDEQ addressing: (1) dewatering, and (2) closure by removal of coal combustion residuals surface impoundments to address remediation of discharges or releases of contaminants into soil and groundwater resulting from coal combustion residuals storage to cleanup levels that meet North Carolina's 2L groundwater standards.

Dewatering the coal ash basin, which includes both the process of bulk dewatering and the removal of interstitial water present in the submerged ash, is necessary to fully excavate the coal ash from the basin to allow it to be repurposed. NCDEQ completed the applicable regulatory requirement in December 2015 for both the Asheville and Sutton sites. The dewatering requirements for the Asheville site were transmitted from NCDEQ to Duke Energy in December 2015 in a letter that also applied those same requirements to other retired Duke Energy sites. The applicable dewatering requirements for the Sutton site's coal ash basins were specifically detailed in the amended and approved NPDES permit in December 2015. Thus, there was not a viable option for immediately converting an existing CCR surface impoundment at the Asheville or Sutton sites to a new CCR landfill in 2014 or 2015 because de-watering requirements were not defined yet by DEQ. This necessitated that some of the site's coal ash be sent off-site for disposal in order to meet the CAMA closure date of August 1, 2019, and DE Progress could not have begun construction of an onsite landfill at Sutton in the timeframe suggested by G&M because the regulatory requirements needed to do so could not have been completed on their assumed schedule.

In regards to the "when is the coal ash excavation complete" question, NCDEQ completed and communicated its regulatory requirements for when the basin is "clean" to Duke Energy in November 2016, in a document called "Coal Combustion Residuals Surface Impoundment Closure Guidelines for Protection of Groundwater." This document, included here as Exhibit 1, discusses the decision making process for the depth of excavation for soil removal; basis for soil sampling grid design; soil sampling methods; lab analysis for constituents of interest; and modeling to support closure. This cleanliness guideline has now been applied to the Ashville 1982 ash basin such that excavation can be considered complete, and such that the combined cycle plant can be built on its footprint, and the level of regulatory detail that we only now have would not and could not have been available at the time

G&M suggests an on-site landfill should have been built at Sutton, thereby precluding that option as a viable choice.

As in the case with de-watering, there was not a viable option for immediately converting an existing CCR surface impoundment at the Asheville or Sutton sites to a new CCR landfill in 2014 or 2015 because cleanliness requirements were not defined yet by DEQ. This necessitated that some of the site's coal ash be sent off-site for disposal in order to meet the CAMA closure date of August 1, 2019. These two additional limitations existed that constrained re-purposing coal ash basins beyond the CAMA moratorium that did not get fully resolved until November 2016, well beyond the time in which G&M suggests that DE Progress should have built an onsite landfill at Sutton.

Q. ARE THERE OTHER REASONS WHY AN ONSITE LANDFILL COULD NOT HAVE REASONABLY BEEN BUILT AT THE SUTTON SITE AS G&M SUGGEST?

A. Yes. G&M are also making incorrect assumptions on the ability to permit and construct a CCR landfill using a "perfect world" scenario without due consideration of the inherent uncertainty of permitting any type of landfill, especially a CCR landfill, and in particular during the regulatory and political environment in 2014.

In September 2014, the Coal Ash Management Act (CAMA) became law requiring the 1971 and 1984 impoundments at the Sutton site be excavated and closed by 8/1/2019. In 2014, the ash basins contained an estimated combined quantity of approximately 6,320,000 tons. This value was later increased to 6,655,200 tons as the bottom of the 1971 ash basin was mapped and reflected previous historical dredging that increased the depth of the 1971 basin. The Sutton ash basins are particularly difficult to excavate because much of the ash lies below the historic groundwater table, requiring extra work to dredge and de-water coal ash from the lower depths of the ash basins. The historic groundwater level is approximately 10' below grade at the Sutton site and is governed by the proximity of the tidal Cape Fear and North Cape Fear Rivers. Given the legal and regulatory constraints I previously discussed, coupled with the complexity of CCR excavation at Sutton and the expected timeline to engineer, permit and construct an on-site landfill, the Brickhaven structural fill was selected as the initial place to begin placing Sutton CCRs.

On November 13, 2014, Duke Energy submitted the initial Sutton Excavation Plan to the North Carolina Department of Environmental and Natural Resources (now NCDEQ) as required by NCDEQ on August 13, 2014 and in fulfillment of the Governor's Executive Order 62, dated August 1, 2014. In general, the scope of work included a description of the construction of an on-site landfill; ash basin excavation activities including the initiation of basin de-watering; site preparation; ash basin preparation and ash removal from the basins. In parallel to transporting coal ash to the Brickhaven structural fill site, Duke Energy was developing an on-site landfill capability in order to meet the August 1, 2019 closure requirements mandated in CAMA.

Unanticipated delays occurred, however, as a result of NCDEQ's unexpected announcement on April 7, 2016 of a new policy of going "beyond state and federal requirements" by conducting an environmental justice review of each Duke Energy coal ash CCR landfill applications along with their requesting the EPA's Office of Civil Rights, the USCCR, and the Advisory Committee to review and approve the environmental justice analysis before the permit could be issued. See Exhibit 2. This delayed the permitting process for Sutton by approximately six months. This is a real-world example of the inherent uncertainty of a landfill permitting process that DE Progress actually experienced for the Sutton site. Other delays could have also happened as a result of unexpected public citizen intervention, an unwillingness of the county to allow landfill construction, unfavorable site suitability determination, etc. As a relevant and recent example, in 2012, the Brunswick County Planning Board denied Operation Service's application for a Special Exception Permit to construct a landfill near Supply, NC in the community of Royal Oak. While I don't want to speculate on what may or may not have happened, I raise these points to show the inherent caution one must use when using "perfect world" assumptions in planning timelines.

In summary, these uncertainties could not be accurately quantified in the Fall of 2014, and missing the required CAMA date was not an option, so a two-part plan that included development of an on-site landfill and some portion (~2M tons) being excavated to an offsite disposition was necessary. The permit to construct the Sutton landfill was issued September 21, 2016.

The permit to operate was issued July 7, 2017. This would have provided DE Progress only 25 months to excavate approximately 6,655,000 tons of ash which is not operationally feasible and would have prevented CAMA compliance.

Q. SHOULD DE PROGRESS HAVE STARTED PERMITTING THE DESIGN FOR AN ON-SITE LANDFILL AT SUTTON IN JUNE OF 2014 AS G&M SUGGESTS?

A. No. CAMA became law on September 20, 2014 and the Geosyntec Report-Closure Options Feasibility Analysis Report, Conceptual Closure Plan LV Sutton Plant was received by Duke in September 2014. As stated previously, DE Progress submitted the initial Excavation Plan to NCDEQ November 13, 2014. The scope of work included construction of the on-site landfill, ash basin excavation activities, initiation of basin dewatering, site preparation, ash basin preparation and ash removal from the basins.

The permitting assumptions described in the G&M testimony are best case and do not take into consideration unexpected delays such as the new policy decision by NCDEQ on requiring environmental justice reviews which added six months to schedule. G&M performed a hypothetical calculation for excavating the two basins containing 5.4 million tons of placing that ash in the on-site landfill. This calculation is flawed, however, and uses the actual ash quantity remaining on site on the date January 17, 2017, reflecting many months of excavation and truck/rail transport to Brickhaven. The actual value for their hypothetical calculation assuming no ash had left the site would have been a minimum of 6,655,200 tons in the basins that required excavation by 8/1/2019. Further, their testimony erroneously assumes "a production rate" of 200,000 tons per month. This value is actually the "ability to receive rate" of the new on-site permitted landfill, and cannot be assumed for the overall production rate, which is limited by the coal ash excavation rate. As stated previously, excavation is more complicated in the 1971 coal ash basin due to the large quantity of ash below the groundwater table that required dredging and de-watering, and thus will yield an expected lower excavation rate than that G&M assumed in their hypothetical calculation. The production rate is expected to vary between ~150,000 – 200,000 tons per month based on site conditions of the ash being excavated and groundwater levels in basins. In summary, Duke Energy made a reasonable and prudent decision in pursuing a combination of the on-site landfill and excavation of ash and transport offsite to Brickhaven, which ultimately was the right decision to comply with the law. G&M have missed essential facts and information that have led them to an erroneous conclusion regarding Sutton, and their suggested disallowance of $80.5 million for costs at that site, while I believe made in good faith, should be rejected.

Q. WHY DO YOU DISAGREE WITH THE CONCLUSION THAT DE PROGRESS SHOULD HAVE BUILT AN ONSITE LANDFILL AT THE ASHEVILLE SITE INSTEAD OF TRANSPORTING CCRs OFF SITE UNDER A CONTRACT WITH WASTE MANAGEMENT, INC.?

A. All the issues that I discuss above for the Sutton site regarding the CAMA moratorium on CCR landfills, regulatory limitations, and erroneous "perfect world" planning assumptions apply equally to the Asheville site and would have similarly made an on-site landfill option infeasible.

Q. ARE THERE OTHER REASONS WHY AN ONSITE LANDFILL COULD NOT HAVE REASONABLY BEEN BUILT AT THE ASHEVILLE SITE AS G&M SUGGEST?

A. Yes. Potential siting and construction of a CCR landfill within portions of the Asheville 1982 basin and limited portions of the 1964 basin was evaluated as early as 2007 prior to the passage of CAMA. However, earthquake and seismic issues, and its physical proximity to the French Broad River prevented this option. A public hearing for a special use permit was held for a proposed landfill on-site in 2007. At that time, the zoning board had concerns regarding its proximity to the French Broad River. Ultimately, based on comments from the board, Progress Energy withdrew its application for a special use permit.

In September 2014, CAMA deemed the two surface impoundments at the Asheville site ('64 and '82 basins) as high-priority, which then established an August 1, 2019 closure deadline. Ash continued to be excavated from the '82 basin, and was transported to the Asheville International Airport structural fill project thru the mid-2015 project completion. The Mountain Energy Act of 2015 (Senate Bill 716) amended the required completion date for closing the two Asheville site ash basins to August 1, 2022, in order to allow time for the construction of a new Combined Cycle Plant in the foot print of the '82 basin. This along with the moratorium per Part III of CAMA and the associated CAMA Section 3.(d) prohibiting the construction of new landfills located wholly or partly on top of a facility that is or ***<u>was</u>***, being used for such combustion products, eliminated the option of a new CCR landfill on the Asheville site.

Thus, while CCR landfill construction on the Asheville site had been researched in the past, CAMA and the Mountain Energy Act of 2015 forever changed the technical feasibility of an on-site CCR landfill. The Mountain Energy Act required construction and startup of a new combined cycle power plant that facilitated the permanent shutdown of the existing Asheville coal ash generating station by January 31, 2020, all while maintaining reliable generating resources in the isolated western grid region. This, in turn, required a site location for the new combined cycle plant, the 1982 coal ash basin, and also required large site areas be reserved for the construction laydown areas necessary to support efficient construction of the new plant. With the footprint of the new combined cycle power plant established and the large site areas dedicated to construction laydown areas to meet the 2020 requirement, there was no longer sufficient land areas left on site to effectively build an on-site landfill in the 1964 basin. Please see Exhibit 3. In summary, while on-site CCR landfills had been researched in the past for Asheville, the Mountain Energy Act of 2015 effectively made construction of a new on-site CCR landfill construction technically unfeasible given the short time period to replace the coal-fired generation by 2020, and close both ash basins by 2022.

Q. IN ADDITION TO ARGUING THAT AN ON-SITE LANDFILL SHOULD HAVE BEEN BUILT AT THE ASHEVILLE SITE, G&M ALSO TAKE ISSUE WITH CERTAIN COSTS THE DE PROGRESS IS PAYING TO DISPOSE OF CCRs AT THE ASHEVILLE SITE. DO YOU AGREE WITH G&M'S POSITION REGARDING THOSE COSTS?

A. I disagree with the quantity of ash excavated and transferred off-site in the G&M analysis. The total quantity of ash excavated and transported from the Asheville site is approximately 1.4 million tons (~550,000 tons from the 82 to 64 basin and 850,000 tons moved off-site). This figure excludes the 354,000 tons of ash excavated and transported to the Asheville Airport structural fill project. G&M's analysis in Exhibit 6 of their testimony is based on a total of 821,000 tons of ash excavated and transported. Including the additional 574,028 tons of ash that they did not account for revises their analysis to a recommended disallowance of $14,208,685 instead of $45,674,748. Reference Confidential Exhibit 4 to my Rebuttal Testimony.

As to the price per ton for ash disposal that DE Progress has paid at the Asheville site, the Company believes that the "all-in" blended contract rate it had for the initial scope of work (2015 - 2016) was reasonable. As we gained greater experience with excavation of the Asheville basins, however, DE Progress was able to negotiate a more favorable all-in rate in December of 2016, an 18% decrease from the original blended rate. With the benefit of hindsight and under ideal conditions that did not have to account for timing constraints and the complexity of excavation, I do agree that DE Progress's initial all-in rate could have been potentially reduced, perhaps to a lower theoretical rate. Thus, if the Commission were to find that the initial, all-in rate that DE Progress negotiated was excessive, a disallowance of approximately $9.5 million could be justified in lieu of the G&M disallowance of approximately $14 million (adjusted down to account for proper ash amounts as discussed above). See Confidential Exhibit 5.

Q. G&M STATE THAT THEY HAVE RECEIVED INCONSISTENT INFORMATION REGARDING THE AMOUNTS OF CCRs AT THE ASHEVILLE SITE. HOW DO YOU RESPOND?

A. I agree that G&M has received a great deal of information in this case, including responses to multiple questions that asked for ash quantities at different times and in different ways. Again, I do not fault them for not having a complete picture given the amount of information that they had to process and, at times, the Company could have provided answers that could have been explained more fully. In any event, however, my previous discussion of ash quantities at Asheville clarifies any confusion as to this topic. Further, there is consistency in the ash amounts in exhibit 5 of the

G&M testimony despite their contrary assertions. The G&M exhibit is comparing responses from multiple questions and testimony which show variations that can be explained. I will explain these one piece at a time.

For PS Coal Ash DR 3.2 - the 3.7M tons was the estimated amount in the 1982 Basin in 2007 prior to any ash being excavated to the airport and other sites. The difference between this estimate and the 2015 ARO figure is the ash that was removed offset by some production ash being put into the basin.

In my direct testimony - Exhibit 9, a conversion factor from yards to tons is used of 1.2 from the December 2015 ARO Estimate. When compared to PS Coal Ash DR 23-1 of 1/1/2015 the difference can be attributed to the conversion calculation.

In my direct testimony - Exhibit 5, this amount ties with the December 2016 ARO Estimate and is rounded to the nearest 100K. When compared to the PS Coal Ash DR 23-1 as of 1/1/2017, this amount ties except for the rounding.

The Asheville DEP Site Cost Estimate (PS Coal Ash DR 5-5D) - ties to the 1964 Basin information provided in my direct testimony. For the 1982 Basin, I do not understand how G&M calculated the 875,186 tons reflected in Exhibit 5 of their testimony. The 1982 Basin excavation was completed September 30, 2016.

Q. G&M RAISE ISSUES WITH SEVERAL CATAGORIES OF POTENTIAL FUTURE COSTS WITH WHICH THEY HAVE CONCERNS. HOW DO YOU ADDRESS THOSE CONCERNS?

A. There are four types of potential future costs that G&M contend may be of concern in the future should certain events take place. These concerns relate to contractual fulfillment fees at the Brickhaven site; water treatment costs; beneficiation timelines; and beneficiation contracts. I will address each one of these items and demonstrate that there are no present or future issues of concern.

<u>Fulfillment Fees</u>

Q. DO YOU AGREE WITH THE G&M ASSERTION THAT POTENTIAL FULFILLMENT COSTS IN RELATION TO THE BRICKHAVEN AND COLON MINES MAY BE UNREASONABLE?

A. No. Keeping in mind that G&M raises this issue as a "heads up" for future costs that may or may not occur, I address this issue from an overall view of reasonableness. For contracts that require a contractor to develop some large infrastructure in order to be able to perform the needed contracted service, it is common practice and totally reasonable to require a minimum investment by the company requesting the contracted service. This is particularly common where the market does not indicate a readily "next available client" to use the completed infrastructure for what it was designed for.

In this case, a large infrastructure development by Charah involved land purchase, permitting cost, rail spur and unloading system construction, landfill construction, and leachate system construction, all of which are necessary to perform the specific contracted service --- receive and place ash as structural fill. The contractor's required development costs are addressed by an "unfullfillment fee", detailed in the Charah contract, and are scaled based on the value of the contractor's development financial investment. This fulfillment fee was contractually negotiated to fairly and reasonably acknowledge Charah's risk exposure for development cost and is not unusual. Furthermore, even if fulfillment fees have to be paid in the future, the costs of those fees, in conjunction with the total cost of the transaction compared to other choices for disposal, are cost effective, but as G&M properly notes, that is an issue for the future, if at all.

Water Treatment Cost Estimates

DE Progress understands G&M's comments suggesting that the Commission pay close attention to future water treatment costs. In developing the 2016 closure cost estimates for DE Progress sites, the Company based water treatment cost estimates on actual costs at the Sutton and Dan River sites given that they were the best sets of actual market prices that DE Progress had at the time. Also, water treatment design and implementation strategies have and continue to mature, and the Company has increasingly accurate cost estimates specific to each site as these plans develop more fully. We will continue to update water treatment cost estimates on a quarterly and annual basis for each specific basin site. On balance, DE Progress's cost estimates for water treatment costs are decreasing, and we expect water treatment costs across all sites to be lower in the next updated comprehensive cost estimates that we anticipate to be completed prior to the end of the year. Accordingly, we do not take any issue with G&M's recommendation that the Commission and interested stakeholders track these costs as they move farther along in their path to maturity.

Beneficiation Timelines

On page 11 of their testimony, G&M make note of the beneficiation timelines assumed for the Weatherspoon, Cape Fear, and H.F. Lee sites and state that G.S. 130A-309.215 will not allow a variance to be had on these sites for site closure deadlines. While G&M do not take any issues with the plans for these sites, they raise this issue as to timing as an issue that DE Progress should be aware of.

I want to first make clear that DE Progress will comply with the deadlines set in applicable laws and will seek variances to any deadlines, as may be applicable, where it would be in the best interest of our customers to do so. In this regard, Section 130A-309.215 reads as follows: [T]he General Assembly authorizes the Secretary to grant a variance to extend any deadline ***under this act***. I read this to mean that the NC DEQ's variance authority is equally applicable to the closure provisions applicable to H.F. Lee, Cape Fear, and Weatherspoon. I understand that prior versions of the CAMA law may not have allowed variances to be sought for certain classifications of basin sites, but the current language that I discuss above appears to have removed any such limitations. In any event, however, DE

Progress will continue to monitor developments and progress at each of these three sites and will comply with applicable laws and regulations as we move forward.

Beneficiation Contracts

On page 12 of their testimony, G&M make the general observation that beneficiated ash storage and management costs may increase if DE Progress does not have ash purchase contracts in place for beneficiated ash. I agree with this general observation, but note that DE Progress is in the later stages of contract negotiation for the sale of processed ash and expects to have an executed agreement by March, 2018. The first beneficiation unit at issue in the G&M testimony is expected to come on-line in late 2019, which would alleviate the issue that G&M raise in this section of their testimony.

Q. DO YOU AGREE WITH GARRETT & MOORE'S HYPOTHETICAL COST CALCULATION FOR SUTTON THAT EXCLUDES TWO SPECIFIC LANDFILL LINER COMPONENTS?

A. No. While these two specific landfill liner components may not be specifically required for other new landfill sites across the State of North Carolina as G&M state, the unique location of the newly constructed Sutton CCR landfill, being immediately adjacent to the existing coal ash surface impoundments, required their use to effectively monitor the new landfill.

The new Sutton CCR landfill design includes a "Secondary Geocomposite Layer" and a "Secondary Geomembrane Material". These additional liners are necessary for the new CCR landfill design to be able to distinctly monitor the landfill's performance separate and apart from any influence that the adjacent older coal ash basins may be having, both now and in the future. Otherwise, it would be difficult to discern if the new landfill liner system was operating properly (or leaking), or whether groundwater monitoring wells around the landfill were actually detecting an effect from the adjacent coal ash basins.

The inclusion of the secondary liners will avoid future costs to potentially excavate and check the liner system for damage. It was therefore prudent to include these two specific secondary liner components in the new landfill design due to its unique siting adjacent to the coal ash basins.

Q. AS A FINAL ISSUE, G&M STATE THAT DE PROGRESS SHOULD HAVE SELECTED THE WEATHERSPOON BASIN AS A BENEFICIATION SITE UNDER CAMA. DO YOU AGREE?

A. No. CAMA section 130A-309-216 requires an impoundment owner to: (i) identify two sites by January 1, 2017 and an additional site by July 1, 2017; and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundments located at the sites. Buck, HF Lee, and Cape Fear have been identified as the three sites based on the best economic value to customers while meeting CAMA compliance. In an effort to pursue additional beneficiation opportunities, DE Progress was able to obtain additional agreements with cement companies to purchase an average volume of 230,000 tons / year from the Weatherspoon site. Because of the fluctuation in the cement marketplace, the cement companies would not guarantee more than this combined average volume of 230,000 tons / year. However, assuming the cement demand continues to rise; the economy stays strong; and the housing market stays strong, the cement companies hope to take greater than 230,000 tons / year but cannot guarantee to take 300K tons / year at this time. Since CAMA requires 300,000 tons / year be beneficiated to qualify under the statute and because Weatherspoon's guaranteed ash take was less than 300,000 tons/year, the Company could not claim this site as one of the three ash beneficiation sites under CAMA. DE Progress agrees with G&M's recommendation to continue to make commercially reasonable efforts to identify additional sites for cost-effective beneficial reuse of ash and DE Progress will continue to do so. The Weatherspoon agreement is a great example of this win-win for the cement industry and for customers.

III. RESPONSE TO CUCA WITNESS O'DONNELL

Q. WITNESS O'DONNELL STATES IN HIS TESTIMONY THAT A NATIONAL COMPARISION OF CCR ASSEST RETIREMENT OBLIGATION (ARO) AMOUNTS DEMONSTRATES THAT DE PROGRESS'S ARO IS OVERSTATED BY 75%. DO YOU AGREE WITH HIS CONCLUSIONS?

A. I do not. By way of analogy, it appears to me that Mr. O'Donnell's analysis has the same significance of taking a list of home sales prices from around the Southeast and the country without regard to the size, location, features, or age of the houses; listing them out in order of greatest to least cost; and then concluding that houses in certain areas of the country are overpriced because they are not the same as houses in other places in America. While Mr. O'Donnell claims that he has taken fair measures to make his comparison of national CCR ARO amounts valid (such as applying a random 65% capacity factor to coal plants located at various CCR sites), I do not see where O'Donnell has accounted for or even considered the following factors in his analysis:

a. The number of coal plants in the company's fleet;
b. The type of coal plants in the company's fleet;
c. The age of the plants in the company's fleet;
d. The type of coal used in each of the plants in the company's fleet;
e. The actual MWe capacity of each coal plant, over their lifetime considering plant upgrades that may have occurred adding generation;
f. The type of environmental controls, if any, installed on the plants in the company's fleet (*e.g.*, electrostatic precipitators, flue gas desulfurization);
g. Whether any plants in the company's fleet utilize dry ash handling;
h. Whether any coal combustion residuals (CCRs) generated from the plants in the company's fleet are being sold for beneficial reuse;
i. The type of CCR basins in the company's fleet;
j. The location of the CCR basins in the company's fleet;
k. Whether other utilities have closed some of their coal ash basins;

l. Soil and other geologic conditions of the CCR basins in the company's fleet;

m. State specific laws applicable to CCR basins in the company's fleet;

n. Regulatory rules and regulations for each state applicable to the CCR costs and AROs in Table 8;

o. Whether any CCR costs have been excluded from the ARO amounts listed in Table 8 (*e.g.*, write-offs);

p. ASPE Cost Estimate Classifications for each ARO amount stated in Table 8;

q. Macro-level assumptions used by each company in deriving the ARO amounts (*e.g.*, basin closure dates, closure methods, etc.);

r. The scope of work assumed in each ARO estimate;

s. Any contracts, RFPs, RFIs, or bidder responses for work to be performed;

t. Comparisons of actual, to-date costs to projected costs in the AROS;

u. Whether any CCR basins were excluded from the ARO amount (e.g. not subject to the Federal CCR rule) and if so, why; and

v. The amounts and types of CCRs in the basins for each company.

Without consideration of these elements, I don't see any reasonable basis for taking Mr. O'Donnell's recommendation seriously and believe that he himself realizes the weakness in his analysis based on his testimony on page 40, lines 1-13. My recommendation is that the Commission consider the reasonableness of DE Progress's ARO amount on its own merits, based on the facts in this case, without regard to the proposal offered by Mr. O'Donnell.

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

A. Yes.

BY MR. BURNETT:

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

A. Yes, I do.

Q. Would you please now present your summary for the Commission?

A. Yes. My rebuttal testimony responds to the direct testimony of Public Staff Witnesses Garrett and Moore and CUCA Witness O'Donnell.

Witnesses Garrett and Moore appear to be the only intervening witnesses who have conducted a thorough and principled analysis of the costs that Duke Energy Progress has incurred to comply with the CCR rule and CAMA, and I agree with the majority of their conclusions. However, based on a complete review of the applicable facts, including several key facts and sets of information that they have overlooked, I do not believe that their suggested disallowances of the Company's coal ash disposal costs are warranted.

First, I disagree with Garrett and Moore's conclusion that DEP could have built an on-site landfill sooner than the Company did. I also disagree with Garrett and Moore's conclusion that DEP could have built an on-site landfill at Asheville site rather than contract with Waste Management, Inc. to transport CCRs to an off-site location. I disagree with the quantity of ash excavated and transported off site that Garrett and Moore used in its analysis of Asheville, which does not account for over 500,000 tons of ash.

Witnesses Garrett and Moore also contend that the Company should have moved approximately 558,000 tons of ash from our Asheville site to our Cliffside site, rather than storing that ash at another location at the Asheville site. Moving that amount of ash from Asheville to Cliffside in the amount of time that the Company would have had to do it would have been virtually impossible. Garrett and Moore's contentions that it could have been done are not correct.

Finally, my rebuttal testimony also addresses the concerns that Garrett and Moore raised with respect to potential for costs to be imprudent in the future if these certain conditions arise. These concerns pertain to costs associated with fulfillment fees, water treatment costs, beneficiation schedules, and beneficiation contract issues, even though Garrett and Moore do not suggest disallowance of any of these potential future costs at this time.

With respect to Witness O'Donnell, his analysis and recommendation of a 75 percent disallowance of DEP's coal ash costs relies on multiple analytical flaws that are fatal to his conclusion. Specifically, I do not agree with his conclusion that the national comparison of CCR assets retirement obligation, or ARO, amounts shows that DEP's ARO is overstated by 75 percent. I enumerate 22 factors that Mr. O'Donnell does not appear to have considered, which must be accounted for in order to seriously attempt this type of analysis. I recommend that the Commission consider the reasonableness of DEP's ARO amount on its own merits, based on the facts of this case, and without regard to Mr. O'Donnell's proposal.

This concludes my summary of my rebuttal testimony.

MR. BURNETT: Mr. Chairman, Mr. Kerin is available for cross examination.

CHAIRMAN FINLEY: Cross examination of Mr. Kerin.

CROSS EXAMINATION BY MR. WEST:

Q. Good afternoon, Mr. Kerin. My name is James West with the Fayetteville Public Works Commission. How are you?

A. Fine, thank you.

Q. As I was understanding your earlier testimony, one of your principle contentions is that Duke Energy Progress' management of coal combustion residuals and its coal ash basin practices are reasonable because they are in line with industry standards; is that correct?

A. And in compliance with the regulations.

Q. Sure. But at least, as to the first part, the answer is yes?

A. Yes. We were in line with the industry standards.

Q. All right. So when you assess Mr. O'Donnell's study, and I'm referring specifically to pages 25 and 26 of your testimony, you listed 22 factors that you just mentioned in your summary, labeled A through V, and you criticized his comparative analysis because he didn't assess any of those 22 factors; is that correct also?

A. That is correct.

Q. All right. Did you, or anyone else at Duke Energy Progress, attempt to assess these 22 factors -- any or all of these 22 factors -- and do your own financial analysis?

A. No, I did not, and let me tell you why. Because I don't feel they are relevant. What's useful for me, information from other utilities are, best practices, and how they are managing their basins and how they are closing their basins, lessons learned. An example is the recent fatality at Kentucky utilities and the closing of one of their basins. Facts and information about how different utilities are managing ash, trends with contractors, the hurricanes in the Gulf of Mexico this year that impacted the suppliers of liner material and how that is going to impact us. That is why I formed the peer team of other utilities to share those best practices and lessons learned. By going through this laundry list of 22 items, I could have gone through -- you'd have to go through basin by basin, site by site, and at the end of the day, it's still not a true comparison of each other's ARO. So I stand by our ARO. It was built from the bottom up. It's been reviewed by management and our external accounting firm.

Q. And just so I understand, that's true for all or any of the 22; you didn't do a comparative analysis of any utilities for any of the 22 factors, correct?

A. I don't think by doing that type of analysis would have added any value to us doing our ARO calculation.

Q. All right. And then when you -- when you mentioned earlier that your practices were in line with other utilities in the industry, did you do any sort of financial analysis when you made that comparison?

A. No. Our analysis with other utilities was their management and operational practices on how they are managing ash.

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

CHAIRMAN FINLEY: Ms. Lee.

CROSS EXAMINATION BY MS. LEE:

Q. Good afternoon, again, Mr. Kerin.

A. Good afternoon.

Q. Just a couple of very quick questions. I'm looking at page 11 of your rebuttal, and in the pages preceding, you were generally testifying about the Sutton site and the timing of closure options there?

A. Yes.

Q. Did Duke seek a variance from CAMA timing requirements at the Sutton site?

A. No, we did not. As you are aware in House Bill 630 and Senate Bill 729, the variance criteria is that you can seek a variance within -- only within one year of the actual required date. So that date would be, at the very earliest, August 1st of 2018.

Q. Okay. Thanks. And when the legislature established the initial CAMA deadlines, is it your understanding that they took into consideration feasibility, or Duke's ability to close those ponds that were designated high priority?

A. I can't speak to what their analysis was.

MS. LEE: Okay. That's all I have.

CROSS EXAMINATION BY MS. TOWNSEND:

Q. Good afternoon, Mr. Kerin.

A. Good afternoon.

Q. First of all, in response to Mr. West's question, you mentioned the peer group that you formed.

Question is, were any of the other utilities in that peer team found guilty of criminal negligence?

A. Not that I'm aware of.

Q. All right. And you also applauded Garrett and Moore for having spoken with employees of Duke and done some site visits.

Do you know if Duke offered to make its employees available to the AGO for informal inquiries?

A. I'm not aware of that.

Q. Is Duke Energy offering that to the Attorney General's Office and other intervenors for the next case?

A. I would imagine we would respect any type of request that would help somebody understand the basis.

Q. If you will go to page 6 of your rebuttal testimony, lines 13 through 16.

A. Okay.

Q. You propose that, had the -- you were speaking about the fact that Garrett and Moore did not agree with your analysis of the statute, and you state here that, had the legislature, quote, intended for the moratorium to have the limited applicability suggested by Garrett and Moore, it would have certainly done so by including limiting language; is that your statement?

A. Yes, ma'am.

Q. Okay. That same applies, does it not, to the fact that the legislator, if it had -- legislature, had it intended for public utilities to be allowed to recover costs related to coal ash compliance, as you say, quote, it would certainly have done so by including, end quote, such language, as it has done so in the past regarding other public utility-related cost?

Using your own rationale, wouldn't that be true?

A. My rationale is true in this case, in this example.

Q. But you agree it would also be true in the next case?

A. I can't -- I'm not familiar with that next -- that's out of my scope.

Q. Okay. If you will go to page 7 of your rebuttal testimony, line 16, starting there, you talk about one of the reasons that Duke Energy Progress was unable to immediately convert an existing CCR surface impoundment at Asheville or Sutton sites to a new CCR landfill was because dewatering requirements were not defined yet by DEQ in 2014 or 2015, and that those regulatory requirements could not have been met on the proposed schedule; is that correct?

A. That is what I say, yes.

Q. Okay. However, as recommended by Mr. Whitliff and by Garrett and Moore, there is nothing that prevented Duke Energy Progress from building a greenfield landfill on those two sites, was there?

A. Can I talk about those sites individually? So Sutton -- I take no issue with the suggestion to build a landfill at Sutton. In fact, we built a landfill at Sutton. It was operational in July this year, and we are placing ash in that landfill today. What I take issue with at Sutton is the timing. Now, we will talk about that Garrett and Moore is using a perfect-world scenario in schedule from engineering, permitting, construction of a landfill and the time to do that, to also include the excavation of two basins with 6.5 million tons of ash that had to be done by 8/1/19. And what I want to talk about, it's disproven by the real-world facts of building a landfill at the Sutton station in that time frame. First, as I list in Exhibit 2, is the environmental justice review. Let me just take you there.

Q. This has been part of your testimony already. I don't know that we need to go into the detail. I think we all heard this before.

MR. BURNETT: Mr. Chairman, may the witness finish his answer?

CHAIRMAN FINLEY: Yes. I think you opened the door to this. Go ahead.

MS. TOWNSEND: Okay. I was just trying to save time.

THE WITNESS: April 7th --

April 7, 2016. This is a statement. "North Carolina to take extra steps to protect minority communities. North Carolina's Chief Environmental Agency announced today that it will go beyond state and federal requirements to ensure minority communities are not negatively impacted by Duke Energy's coal ash landfills. Assistant Secretary Tom Reeder made the announcement at a town hall meeting in Walnut Grove where he discussed the McCrory administration's leadership in addressing the decades-old issue with coal ash. The McCrory administration is a national leader in addressing the decades-old issue of coal ash and continues to set examples for the federal government and other states on this issue.

"Assistant Secretary Tom Reeder said the McCrory administration will go beyond federal and state requirements to protect minority communities from negative impacts when evaluating Duke Energy's application to store coal ash in a new landfill. The State Environmental Department will conduct an environmental justice review of each Duke Energy coal ash landfill application and ask the EPA Office of Civil Rights, the U.S. Commission on

Civil Rights, and the North Carolina Advisory Committee to review and approve the environmental justice analysis before the permit is issued.

"The additional review by outside groups with expertise in environmental justice issues will help ensure Duke Energy's construction of a landfill will not have an adverse disparate impact on the minority or low-income community protected by Title 11 of the Civil Rights Act of 1964."

That was one of those unforeseen real-world issues that we had to face. That came out -- that was done on April 17th when our permit was pending approval. We -- that caused about a six-month delay in getting our permit.

BY MS. TOWNSEND:

Q. Which, as you have already testified, will be the basis of seeking an extension of the statutory deadlines; correct?

A. We have not seeked that extension through the variance. But I also want to add that, when I talk about real-world events that are not included in Garrett and Moore's schedule, is Hurricane Matthew in 2016. Right after we received our permit on September 21, 2016, we were impacted by Hurricane

Matthew. We also -- you brought up the issues of dewater, so -- and why dewatering is so perfect -- important to build an on-site landfill. Putting an on-site landfill is the construction of the landfill. We have to be able to dewater the basin to move that ash to the on-site landfill.

So on August 24th of 2014, DEQ issued what they call the DECAM (phonetic spelling) letter, which allowed us to start moving bulk water off of those basins. Within two weeks, they recanted that letter and told us we could not start moving bulk water. The next revision letter didn't come out until 12/17/15, almost a year delay, allowing us to remove bulk water. That was revised again on 7/20/16, where it added additional requirements. So that's another one of those issues that were unforeseen in 2014 that would have impacted Garret and Moore's perfect schedule if it all would have lined up.

Another issue we had, we were awaiting DEQ's guidance on what "clean" is. So to meet our final closure date of August 1, 2019, we had to close that basin and have it clean, and we were waiting -- this was pending DEQ's providing guidance on what that means. That guidance didn't come out until

November 16th, which is also unforeseen impact that we were planning for.

So in that perfect-world solution, even if we would have met all those primary dates, and we would have had that landfill starting operation on July of 2016, as Garrett and Moore contend was available, transporting 175,000 tons per month into that landfill, which is optimistic, with the conditions at Sutton, it would have taken approximately 37 months, which would have taken us a year over our compliance date, and that would have provided no weather days, no contingency. Everything would have had to have gone perfect, sunny days, full transport. And my concern is, I think I would be in a different conversation today -- here today, if I would have gambled and put everything based on a landfill, knowing that there is unforeseen issues that could prevent that landfill, and I would have been way behind schedule in making my August 1, 2019 date to move 6.5 million tons of ash.

Q. Thank you, Mr. Kerin. Okay. Looking at your rebuttal testimony on pages 14 and 15, on page 14, lines 12 through 19 --

A. Okay.

Q. -- you indicate that, "Potential siting and construction of a CCR landfill within portions of the Asheville 1982 basin and limited portions of the 1964 basin was evaluated as early as 2007, prior to the passage of CAMA," correct?

A. That is correct.

Q. "However, earthquake and seismic issues and it's physical proximity to the French Broad River prevented that option," correct?

A. That is correct.

Q. All right. And if you go to page 15, lines 10 through 19, you said that, "While CCR landfill construction of the Asheville site had been researched in the past," which we just discussed, "CAMA and the Mountain Engineer -- Energy Act of 2015 forever changed the technical feasibility from on-site CCR landfill. The Mountain Energy Act required construction and starting up of a new combined-cycle power planted that facilitated the permanent shutdown of the existing Asheville coal ash generating station by January 31, 2020, all while maintaining reliable generating resources in the isolated western grid region. This, in turn, required a site location for the new combined-cycle plant, the 1982 coal ash basin"; is that correct?

A. That is correct.

Q. So apparently, my reading of those two pages, Duke Energy Progress determined that it was prudent to build an entire new combined-cycle power plant on that closed coal ash basin, but it determined that it was not safe to build a lined landfill on that same basin; is that correct?

A. What I was talking about is, in 2007, we were -- we proposed a special-use permit to consider a landfill at that basin. The -- at that time, the zoning board had concerns with the proximity of the French Broad River, and it's also an issue from a seismic zone. So that's -- and ultimately, we pulled that back and did not proceed with building that landfill. The Mountain Energy Act requires us to shut down the Asheville coal plant and provide for a combined-cycle site. I think we can safely build a combined-cycle site at that location and would not impact the French Broad River. If you recall on the maps I submitted to the Public Staff, the question on location, where you could build a landfill at the Asheville site, the primary location where you had space available would have been the '82 basin. The '82 basin now is where the combined-cycle is being built.

So it -- what I'm saying here is it eliminated the option to find another location or build a landfill at the Asheville site.

Q. Does it take away the concerns of the seismic condition and the fact that it was near the French Broad?

A. I imagine if designed, a combined-cycle will take it out of your consideration.

Q. Hope so.

MS. TOWNSEND: If I may, Mr. Chairman, I have a cross exhibit that I would ask to be marked as Attorney General Kerin Rebuttal Cross Exhibit Number 1.

BY MS. TOWNSEND:

Q. And as that -- as that's being distributed, going to page 9 of your testimony, you mention that, in 2014 or '15, Duke -- the Department of Environmental Quality had not yet set standards for dewatering; we just discussed that, correct?

A. That's correct.

Q. Do you recall when I asked you, during the direct cross, about Ms. Good's letter to the Governor and to DEQ, you stated that dewatering was the first step in closing coal ash ponds?

A. Yes. That is the first step --

Q. Okay.

A. -- in closing a coal ash pond.

Q. Prior to 2014, had Duke Energy Progress dewatered the ash ponds connected to closed sites?

A. No. We had not started dewatering yet.

Q. Okay. Looking at Kerin Rebuttal Exhibit 1, do you recognize that document?

A. Yes, I have seen this document.

CHAIRMAN FINLEY: Do you want me to mark that? We will mark that as AGO Kerin Rebuttal Exhibit -- Cross Exhibit Number 1.

MS. TOWNSEND: Thank you, Mr. Chairman.

(Whereupon, AGO Kerin Rebuttal Cross Examination Exhibit Number 1 marked for identification.)

BY MS. TOWNSEND:

Q. And the title of that document is "Decommissioning Cost Study, Near-Term Units to Be Decommissioned, Progress Energy, January 2012," correct?

A. That is correct.

Q. Okay. If you look at -- first of all, to page ES-1 of the document, at the bottom of the page it indicates that there is a decommissioning cost summary for four DEP sites: Cape Fear, Lee, Sutton and Weatherspoon, correct?

A. That is correct.

Q. All right. Now, if you go to page 3 point -- I'm sorry 3-2 of the document -- excuse me -- it shows a title "General Decommissioning Assumptions for All Sites," correct?

A. Yes.

Q. All right. And then if we go to 3-4, and you look at number 18, if you'll read number 18 for us.

A. "Existing ash ponds will be pumped dry, filled with inner debris, and capped with a 40 mil geomembrane, geonet drainage layer, 18 inches of soil, and a vegetative covering."

Q. Okay. And is this the same requirements under CCR and CAMA that --

A. No, it is not.

Q. -- have to be met?

A. No, it's not.

Q. Okay. Can you explain the differences, please?

A. Well, it would depend on the ash pond. I mean, this is talking about an ash pond which is capped in place.

Q. All right. And are any of the four that we talked about, Weatherspoon, Cape Fear, Sutton, or Lee, a cap in place?

A. H.F. Lee?

Q. Yes.

A. No, they are not.

Q. None of them are?

A. No.

Q. All right. So what was the purpose of this commissioned study?

A. I think the purpose -- and I was not there, and I did not commission this study -- was to start to explore the cost of decommissioning sites that -- or plants that were going to be decommissioned in the near term, is my understanding of it.

Q. As of 2012, correct?

A. Yes. Well, January 2012 is when this study was done.

Q. Correct. Correct. So as of 2012, there is already some assumptions being made as to how you would cap in place those -- at least those four sites; is that correct?

A. Yeah. By Burns & McDonnell, who did this study, although that's a very -- one bullet on how to close a basin is very high level.

Q. And you said it differed from what it would be under CCR or CAMA? Could you just, in general -- I understand site by site --

A. I have to look at the rules. I'd have to look at the rules exactly how we have those.

Q. Oh, you don't know that, okay.

A. I provided yesterday -- I think we looked at the -- in my direct testimony there is an illustrative document of what a cap in place looks like, if you want to go back to that document.

Q. No. That's fine. Earlier, you heard Commissioner -- I know you were here in the hearing room -- you heard Commissioner Finley ask Mr. Maness how to understand the specific components of a coal ash cost the Company is seeking to recover both historically and prospectively.

Where in your testimony and exhibits can we find those costs, such as dewatering per pond or per plant, cost of cap per pond or per plant, cost of covering with soil or vegetation per pond or per plant?

A. I don't have that in my testimony, but that was a data request that we provided to Public Staff.

In fact, when we met at the Mayo plant, we walked through those detailed estimates with our work breakdown structure of the total cost to mobilize and site preparation, fencing around the site -- these are examples for Sutton -- dust control, we had to modify transmission line, relocate a gas line, relocate a different gas line, rail maintenance, truck scales. So there is various items that we reviewed, and this is how we make -- we do our estimates, and we build up to the arrow. So this -- each one of the estimates for each site has been provided in a data request.

Q. And that can also be provided to the Commissioners so they could have answers to those questions, correct?

A. Yes.

CHAIRMAN FINLEY: If we could respectfully request that that information be presented to the Commission as a late-filed exhibit.

MR. BURNETT: Yes, Mr. Chairman. Just for clarification, Exhibits 10 and 11 to Mr. Kerin's direct testimony are the ARO amounts and the breakdown that he's speaking of. Those are the documents that built that. I will supply them.

They are on diskettes, given the volume, so we have complete sets of diskettes. We will get with the reporter and figure out the best way to get those into the record due to the magnitude.

CHAIRMAN FINLEY: Thank you.

MS. TOWNSEND: That's all the questions we have at this time.

CROSS EXAMINATION BY MR. RUNKLE:

Q. Mr. Kerin, may I suggest that you misread the press release, your Exhibit 2? Just look at the final sentence. It should be Title 6.

A. Oh, I'm sorry. I'll look at that. Let me pull that up. It is Title 6. I apologize.

Q. Thank you.

A. That was my error.

MR. RUNKLE: No questions.

CHAIRMAN FINLEY: Mr. Dodge?

MR. DODGE: Thank you, Mr. Chairman.

CROSS EXAMINATION BY MR. DODGE:

Q. Good afternoon, Mr. Kerin.

A. Good afternoon.

Q. Before I start with some of my questions, I just want to follow up on the discussion you had with Ms. Townsend about some of the unforeseen issues that you indicated may have affected the possibility of having the Sutton on-site landfill built within the time frame provided by CAMA. You specifically mentioned environmental justice review.

Could that have also resulted in delays at the Brickhaven structural fill facility?

A. I don't believe so. I think what the DEQ is talking about, what they put for environmental justice reviews were Dan River, application for an on-site landfill, and the Sutton landfill.

Q. Could the decant guidance that you talked about have affected the Company's ability to begin removing ash promptly to the Brickhaven structural fill facility?

A. Yes.

Q. Could the closure guidance for a clean closure of the basin also have affected the schedule for the structural fill facility?

A. It wouldn't have affected the structural fill facility. What it would have affected is how would we know when we are finished. It was our looking forward, when we had the ash hut, were we going to meet all the requirements that DEQ had? We were waiting on that guidance, which we received in November 2016. But it would not have impacted removing ash. It would have been, at the very end, did we close it, and was it clean appropriately.

Q. Okay. And then you also mentioned Hurricane Matthew and the potential delays that could have -- that could have caused for the site?

A. Well, it did cause -- discussion at the site. But we received our construction permit on September 21st. I think Hurricane Matthew was about two weeks later, so it did have an impact.

Q. And it could have also had an impact at the Brickhaven facility?

A. It may have. I was not aware of any impacts to Brickhaven facility.

Q. And do most of these contracts -- or the -- do the contracts in these various legal obligations the utility -- the Company faces with regard to these timelines have force majeure provisions that would be applicable in those types of circumstances?

A. Typically, yes, they have force majeure.

Q. Okay. Thank you. So move into kind of a discussion about some of the points of disagreement that were raised with Garrett and Moore's testimony.

In your rebuttal testimony, you recognize that Garrett and Moore conducted a comprehensive analysis of the closure options developed by DEP and the cost it would incur today. I think this is on page 3 and 4 of your testimony. But you disagreed with their recommendations; is that correct? You highlighted some of those disagreements in your summary today.

A. Yes.

Q. Okay. And more specifically, with regard to the adjustments Garrett and Moore recommended for Asheville and Sutton, you took exception with several of the assumptions supporting their conclusions; did you not?

A. Yes, I did.

Q. Okay. And, specifically, you indicated on page 11, line 18, and you mentioned this in your comments today, that they use some perfect-world assumptions in their analysis?

A. Yes.

Q. Okay. And for purposes of this analysis, would you agree that we should be focused on what DEP -- excuse me -- knew or should have reasonably known at the time it was making these closure decisions?

A. Well, the closure decisions at Sutton were -- it's a high priority site. So it required us to excavate and close those basins by August 1, 2019. So the decision was made through CAMA that we had to excavate that site.

Q. But in terms of the closure option to accomplish that August 1, 2019, deadline, weren't you making those commitments, entering into obligation and closure plans in 2014?

A. Yes. And as I mentioned before, we were required by November 14th of 2014 to submit our excavation plan to DEQ. That was based on an August 13th letter we received requiring that plan to be submitted. As you talked about, in my direct testimony is our plan, and that excavation plan was twofold. Number one was build an on-site landfill. That was our plan initially, and it was always our plan. Two was, realizing the time to build a landfill. Typically, to have it in operation two to three years, moving 6.5 million tons, I could not afford to just put everything into an on-site landfill and wait for that permit to come in. I just talked about some of the real-world issues that we faced that impacted receiving that permit. So we went ahead with the engineering and permitted landfill. At the same time, we started to move ash. We moved 2 million tons of ash to Brickhaven. When the landfill went operational, we ceased operation at Brickhaven, and we have been moving ash to that landfill since July 7th of this year.

Q. And many of those decisions were made in 2014?

A. They were made in 2014 as we were developing our excavation plan to submit to the State.

Q. Based on the information that you had available at the time?

A. Based on the information we had knowing the tonnage, knowing the amount of ash, knowing the conditions of the Sutton basins, knowing that, once you take the dry ash off the top, you are working in a very wet condition. In fact, today, we've removed what I would call the easier ash, and that -- we were able to produce at about 200,000 tons a month. Now, we have to dredge, because we are basically underwater. We dredge into the '84 basin, let the ash decant, water goes back to '71, and then we dry out the ash and we take it to the landfill. That production rate now is about 150,000 tons a month.

Q. Thank you. So continuing with Sutton, could you turn to page 9 of your testimony and tell me when you are there?

A. Yes.

Q. All right. Excuse me. On the bottom of page 9 and carrying over to the top of page 10, you note that DEP, in 2014, estimated the ash basins contained an estimated combined quantity of approximately 6.32 million tons; is that correct?

A. That is correct.

Q. And that value is later updated to, as you indicated in your testimony, 6.65 million tons; is that correct?

A. That is correct.

Q. Okay. But for planning purposes in 2014, would you agree that 6.3 million tons was the estimate used by DEP at the time it was considering closure options at Sutton?

A. That's what we anticipated to be in that basin at the time before we did additional mapping, core boring, and started getting deeper into the 1971 basin.

Q. Thank you. Turning to page 11 of your rebuttal testimony.

A. Yes, sir.

Q. And line 1 you note that unanticipated delays occurred in the on-site landfill permitting process as a result of NCDEQ's unexpected announcement of their plan to conduct an environmental justice review at the site, correct?

A. That's correct.

Q. And we just talked about this exhibit in your testimony?

A. Exhibit 2.

Q. So you indicate that this was unanticipated and unexpected. So do you agree that that was not something the DEP knew or should have known at the time it was making the closure decisions for the Sutton facility?

A. When we made the closure decision, again, our plan was to do an on-site landfill. What that impacted is when we expected to receive the construction permit. We were expecting to receive that construction permit around that April or May time frame, and then we were surprised by the April 7th announcement that, before that permit would be issued, that we add -- the DEQ added these additional, above-and-beyond requirements to do that analysis of the environmental justice review.

Q. All right. So it did impact the time frame; that's one of those real-world situations that arose that was unexpected and unanticipated by DEP at the time it made its --

A. We were not expecting that review.

Q. Okay. Thank you. And you indicate, lower down on page 11, at lines -- I believe it's 7 and 8, that this process delayed the permitting process approximately six months; is that correct?

A. Yes.

Q. Okay.

MR. DODGE: Mr. Chairman, at this time I would like to introduce the first cross examination exhibit for the Public Staff. I would just note this document was originally marked as Kerin Direct Exhibit. I'm repurposing the report. Rather than reprinting it, I just marked in handwriting that this is now Public Staff Kerin Rebuttal Exhibit, and I'd ask it to be marked as Exhibit Number 1.

CHAIRMAN FINLEY: All right. This document dated April 13, 2017, is marked for identification as Public Staff Kerin Rebuttal Exhibit Number 1.

(Whereupon, Public Staff Kerin Rebuttal

Exhibit Number 1 marked for identification.)

BY MR. DODGE:

Q. Mr. Kerin, this, again, is a report from the -- by the court-appointed monitor in compliance with the plea agreements that were entered into by Duke Energy with the U.S. Department of Justice.

Are you familiar with these court-appointed monitor reports?

A. Yes, I am.

Q. Okay. Could you turn to page 8 of the report and let me know when you are there?

A. I'm there.

Q. So I actually -- this is, again, the repurposing. Please ignore the mark on this page. This was for direct testimony. I would like you to focus on the paragraph just above that that begins -- the third full paragraph that begins with, "In 2016."

A. Okay.

Q. Could you read that paragraph? Ms. DeSouza's going to show it on the screen here as well.

A. "In 2016, Duke excavated a total 1,211,325 tons of ash from the Sutton site. The ash was transported by rail and truck to the Brickhaven structural fill site in Chatham County, North Carolina. Duke also planned to begin developing an on-site landfill to provide additional capacity and expedite the excavation of work in mid-2016. However, following the unanticipated delays of approximately four months due to the environmental justice review described above, the construction permit for the landfill was not received until September. Landfill construction began in October, and Duke expects the first cell to be operational in the third quarter of 2017. The site's excavation rate will increase to over 200,000 tons per month when the landfill becomes available."

Q. Thank you. So here the court-appointed monitor report also refers to this delay by the environmental justice review as unanticipated, and it indicates that it would result in approximately a four-month delay; is that correct?

A. That's what he indicates.

Q. Thank you. Now, keeping this same paragraph in mind, and particularly the last sentence, I'd like to ask you to turn to page 13 of your rebuttal testimony.

A. Okay.

Q. Starting on line 2, you state that, "Garrett and Moore's testimony erroneously assumes a production rate of 200,000 tons per month"; is that correct?

A. That's correct.

Q. And you go on to state that, "This value is actually the ability-to-receive rate of the new on-site permitted landfill and could not be assumed for the overall production rate, which is limited by the coal ash excavation rate"; is that correct?

A. That's correct.

Q. Okay. So doesn't the court-appointed monitor's report above indicate that the excavation rate will increase to over 200,000 tons per month once the landfill becomes available?

A. I can't speak to increase to over 200,000 tons a month, because we -- at the time of this report, we weren't -- the landfill wasn't in place, I don't think. What the concept there was, the landfill was designed and built to receive up to 200,000 tons a month. That's not production ash. Early on, as I explained, in 1971 basin, it was a stack in the '71 basin, relatively dry ash, easy to get to, easy to move. At that point, we could move 200,000 tons of ash. Now, the easy ash off the top, we are past that. Now, we are into working with dredges and working --

for the most part, what ash is left in '71 is below water. So we won't receive -- or won't be able to meet 200,000 tons a month with the ash in that condition. And that was anticipated when we mapped out our production rates with our contractors, we knew, once we got past the ash stack, it was going to drop considerably.

Q. Thank you. And that's a helpful explanation. I appreciate that information.

MR. DODGE: Mr. Chairman, at this time I would like to distribute two more cross examination exhibits. These are both related to Sutton as well. (Pause.) Mr. Chairman, I request that the first document, DEP's response to Public Staff coal ash data request 28-2, be marked as Public Staff Kerin Rebuttal Exhibit Number 2.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, Public Staff Kerin Rebuttal Exhibit Number 2 marked for identification.)

MR. DODGE: And the second, the ash basins strategic action team agenda, be labeled as Public Staff Kerin Rebuttal Exhibit Number 3.

CHAIRMAN FINLEY: I don't think I got

that one yet.

MR. DODGE: It should have been included, just a couple of pages at the end.

CHAIRMAN FINLEY: That should be marked as Public Staff Kerin Rebuttal Exhibit Number 3.

MR. DODGE: Thank you, Mr. Chairman.

(Whereupon, Public Staff Kerin Rebuttal Exhibit Number 3 marked for identification.)

BY MR. DODGE:

Q. Mr. Kerin, have you had a chance to take a look at that first rebuttal exhibit?

A. Yeah. I looked at it.

Q. All right. Yeah. This is the nonconfidential response DEP provided to the Public Staff in response to data request 28-2, and on the third page, you could see a bracketed file entitled "DR Public Staff," or PS 28-2 2B, "Sutton transportation and tonnage plan," that was imbedded in the response.

A. Okay.

Q. Do you see that? And that's -- which I included in pages 5 and 7 of this exhibit.

And that document reflects the tonnage and transportation planning assumptions used by DEP in conducting its analysis of the Sutton hybrid closure plan; is that correct?

A. I believe so, yes.

Q. Okay. And I apologize for the fine print and the light copy of this document, but I asked Ms. DeSouza to help put the main points in the screen here that I would like to make from this spreadsheet.

So first, just to make sure that the headers are clear for everyone, starting on the left side of the document, this describes the off-site hauling to Brickhaven by Charah, starting with the truck hauling in the far left three columns, and then continuing to the rail hauling in the middle columns; is that correct?

A. (Witness peruses document.)

Yes. I'm trying -- it's difficult to read.

Q. Yeah. It's very faint. I apologize for the copy quality. And now -- and each row in this table represents one week of activity, as indicated in the column entitled "week ending"; is that correct?

A. Yes.

Q. All right. Now, shifting to the right side of the table, these columns indicate the amount of ash being placed at the Sutton on-site landfill, and the last two columns indicate the total tons per week and the cumulative total; is that correct?

A. (Witness peruses document.)

Yeah. Project cumulative.

Q. Yeah. Project cumulative I think is total tons moved from the site. All right. Thank you.

Now, I am going to direct your attention to near the bottom of the first page where, I think six rows up, it indicates, in March 2017, the facility will begin to handle 56,250 tons per week; do you see that number?

A. Yes.

Q. And I apologize for asking you to do math on the stand here, but subject to check, would you agree that 56,250 tons per week times four weeks is the equivalent to approximately 226,000 tons per month?

A. That's correct.

Q. And this number in that second-to-last column, the 56,250, reflects the amount planned for excavation, not the amount to be received or transported by the different methods; that is correct?

A. I believe that's correct.

Q. All right. And now, if you look at the remaining 2 pages, scanning through, you will see nearly all the weeks showing all the way to the closure date indicating assumed excavation rate of 56,250 tons per week. The only weeks are down, in December 2018, there are four weeks that show a reduced production schedule. So there is no assumed reduction as you get in below groundwater, or barges, or dredges, or anything would have to be included; it just shows a steady 56,000?

A. I think that's how this -- this is just a linear. It looks like somebody just took it and subtracted -- or just divided.

Q. But these are Duke's assumptions, correct?

A. I'm not sure the -- I didn't provide this. It came from Duke, but.

Q. Okay. All right. So -- now, flipping to the last page of the chart, the last row indicates that Duke -- or excuse me, DEP would remove its last 56,250 tons the week of March 3, 2019; is that correct?

A. That's correct.

Q. All right. So looking at that -- and it shows that the last -- the far right, the last number, that they would have removed a total of 7.3 million tons of material from the site; that is correct?

A. That's correct.

Q. So that volume exceeds even DEP's most current estimates of ash quantities in the '71 and '84 impoundments at Sutton; does it not?

A. That's correct.

Q. So most likely, would that additional ash maybe include the ash from the lay-of-land area?

A. It appears that it is probably the lay-of-land area.

Q. Okay. And that's not subject to the same August 1, 2019, closure?

A. No, it is not.

Q. Thank you. So, before we leave this document, I just want to make sure I'm clear here, these were assumed production rates that DEP utilized and provided to the Public Staff to support its analysis of the Sutton closure plan?

A. It looks like an early production schedule, but when I look at the linear numbers, the same every week, my discussion and work with the project team, we are not going to deliver at that production rate every week. So I think this was an early analysis. If we could meet the same amount every week, to plan on meeting that, as we get deeper into the basin, I think this is just a linear, if you took so many a month --

or so many a week, what would it take to get there?

Q. And these are the assumptions that Garrett and Moore based their analysis on.

So, would you say that Duke was using perfect-world assumptions at this time in making this analysis?

A. In this case, it looks like it's a linear analysis.

Q. So a big part of the disagreement between Garrett and Moore and Duke is when Duke should have started acting on the on-site landfill; is that correct, what date they should have committed to that closure plan and begin moving forward the permitting process for that facility?

A. We committed to that plan in our November 2014 response to the State, and we submitted our first permit, I think it was in May of 2015, once we were complete with the engineering analysis and the preparing the permit.

Q. And it's Garrett and Moore's position that Duke should have started that -- the process for the on-site landfill at the same time Duke was beginning its investigation of the Brickhaven structural fill facility; is that correct?

A. Well, it would be -- Charah was the structural fill facility. In their RFP they were gonna go and develop that structure.

Q. Okay. Great. Thank you. So can you turn to Exhibit Number 3, Public Staff Kerin Rebuttal Cross Exhibit Number 3, this is the ABSAT agenda that was distributed.

A. Okay.

Q. And I didn't include a cover page for this. I apologize for this, but this document was included in materials related to the ABSAT organization that was provided the Public Staff in response to coal ash data response 4-7, and it was marked nonconfidential.

If you turn to -- well, first, on the first page, you were involved in the ABSAT team during its operation in 2014; is that correct? We talked about this yesterday.

A. Yes, that's correct.

Q. Turning to the second page, you noted -- if you would, please note at the top of the second page the date at which this agenda -- the meeting date that this agenda was prepared for?

A. Yes.

Q. What is that date?

A. April 25, 2014.

Q. Thank you. And looking down through that second page, I see your name indicated next to several of the agenda topics on that page; do you see your name on that page?

A. Yes, I do.

Q. Were you likely present at this meeting or participating by conference call in this meeting?

A. Yes, I was.

Q. All right. Thank you. Now, at the bottom of that second page, do you see the heading entitled "Number 2, Strategic Projects Per Governor's Letter"?

A. Yes.

Q. All right. And I assume that this Governor's letter that's referred to here is the March 2014 letter from Lynn Good to Governor McCrory we discussed yesterday?

A. I'm sorry, which one were -- what line are you on again?

Q. So this is on page 2 of the exhibit, at the bottom, it's item number 2 on the outline, "Strategic Projects Per Governor's Letter."

A. Okay. I understand. Yes.

Q. All right. And so that reference to the

Governor's letter, was that the same letter we were discussing yesterday -- most likely the same letter we were discussing yesterday?

A. I believe it was.

Q. Okay. And that letter, if you recall, on the second page, we discussed that indicated the time frames that Duke was accelerating planning and closure of the Sutton ash ponds to include evaluation of possible lined structural fill solutions and other options at that time, in March 2014?

A. Yes.

Q. Now, looking down -- back on Exhibit -- Rebuttal Exhibit Number 3, if you look down at the sub 2 item labeled Sutton; do you see that item?

A. Yes, I do.

Q. Could you read what it says under that Sutton item?

A. "Closure project initiated. Target completion 1 September."

Q. And then continuing with the sub 1 below that.

A. "Evaluating nearer-term structural fill opportunities and accelerated dewatering."

Q. All right. And so at this point, Duke was looking -- it indicated in the Governor's letter that it was looking at structural fill options -- in this April 25, 2014, agenda for the ABSAT group -- was looking at structural fill opportunities for the Sutton facility; is that correct?

A. Yes. That's what the agenda item indicates.

Q. And it doesn't indicate an on-site landfill at that time?

A. Not at that time. And I think you have to put it into perspective. This is on 4/25. The ABSAT team was created towards the end of February. So this is very early work. The team knew we were already in place with structural fill at Asheville, and I think it -- not recalling exactly three-and-a-half years ago that discussion, I think this is an item that someone was probably assigned to from the previous meeting to take a look at, are there structural fill opportunities for Sutton. We are already doing it at Asheville. This isn't the final closure plan. CAMA is not in place yet. This is exploring options and taking a look at potential closure options.

Q. Thank you. So -- and I believe yesterday you discussed with Ms. Downey that DEP was conducting RFPs during the summer of 2015 for structural fill or

beneficial reuse options?
A. I think it was -- overall, it was the options looking for RFP and feedback on excavating several of the sites.
Q. Including disposal of structural fill or --
A. We left that option up to the vendors, if they came back with the -- we want to know exactly what they are going to do with the ash.
Q. And so the question I have -- we continue to have is, based on the information that DEP knew at the time in 2014, why was DEP not, instead, making similar efforts at this time to move forward with an on-site landfill that was -- that was expected to be a significantly lower cost?
A. Well, we -- the earlier study that you mentioned is the Geosyntec study. They were looking at options. We received that report in September of that year, at the same time -- of 2014, about the same time I think CAMA became effective September 21st. So we were moving forward with RFPs to excavate. At the same time, we were planning an on-site landfill, which is spelled out in our November 14th excavation plan that was submitted to the State.
Q. So before we leave the Sutton facility, I

have one last question regarding your testimony on page 11. So back to your testimony.

A. Okay.

Q. I will get there myself. So on page 11, line 13, you state that, as a relative -- excuse me, "As a relevant and recent example, in 2012, the Brunswick County Planning Board denied an application for a landfill permit near Supply, North Carolina"; is that correct?

A. That's correct.

Q. Was that a -- that landfill application for a CCR landfill?

A. No, it was not.

Q. All right. Subject to check, would you agree that this was an application related to an MSW landfill, a municipal solid waste landfill?

A. Yes, subject to check, but I believe it was.

Q. And would that landfill, the MSW landfill, have resulted in increased truck traffic and other potential off-site impacts in the local community that could have raised concern?

A. Potentially. I'm not sure how the material was going to be moved at that landfill.

Q. All right. Thank you. Let's move on to

Asheville for a bit. So in your summary today -- flip back there real quick -- you stated that Garrett and Moore's supplemental analysis or supplemental testimony would have resulted in -- this is on page 2 of your summary. At the top of page 2, you state, "Moving that amount of ash from Asheville to Cliffside in the amount of time that the Company would have had to do it would have been virtually impossible, and Garrett and Moore's contentions that it could have been done are not correct." So I think yesterday when -- were you present when Mr. Moore and Mr. Garrett were being cross examined yesterday?

A. Yes, I was.

Q. And Mr. Burnett asked -- was going through a hypothetical example, and Mr. Moore and Mr. Garnett -- excuse me -- Garrett asked following that, what time frame are you talking about? Do you recall their response, "What time frame are you talking about?"

A. I remember the conversation.

Q. Well, that's -- I think "in the amount of time" in your summary is what I would like -- that statement, "in the amount of time that the Company would have had to do it," I would like to explore that a little bit more with you.

A. Okay.

MR. DODGE: Mr. Chairman, at this time, I would like to introduce my last two cross exhibits. I request that these would be labeled as -- well, wait until they are distributed here.

Mr. Chairman, I request these be labeled, the first one, the colored bar chart, be labeled as Public Staff Kerin Rebuttal Cross Exhibit Number 4.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, Public Staff Kerin Rebuttal Cross Examination Exhibit Number 4 marked for identification.)

MR. DODGE: The second one, the '64 basin ash quantity analysis, Foster Wheeler, be labeled as Public Staff Kerin Rebuttal Cross Exhibit Number 5.

CHAIRMAN FINLEY: Shall be so marked.

MR. DODGE: Thank you.

(Whereupon, Public Staff Kerin Rebuttal Cross Examination Exhibit Number 5 marked for identification.)

BY MR. DODGE:

Q. Mr. Kerin, turning first to the colored bar

chart. You haven't seen this document before, so let me establish a little foundation for the document. If you turn to the second page of it -- get my copy in front of me too -- second page of the handout, you'll note that this was -- this indicates that the information was drawn from DEP's nonconfidential response to Public Staff data request 28-22?
A. Yes.
Q. Is that correct?
A. Yes.
Q. All right. And then you can see, if you flip to the -- what would be the back of that data response where it indicates there were imbedded files or attached files, the last of those imbedded files was entitled "Public Staff 28-21 and 22, Ash Tracking Data Final." All right.
And the next four pages after that are excerpts from that Excel spreadsheet. I just printed those four for illustrative purposes here, but would you -- are you familiar with these tracking tables -- these tracking sheets?
A. No, I'm not. I haven't seen these.
Q. Okay. All right. Would you agree that these tables represent DEP's actual tracking records for the

ash being removed from the Asheville facility in 2015 and 2016?

A. Yes, subject to check.

Q. Subject to check. Thank you. And the table shows the source of the basin of the ash -- if you look at the Excel spreadsheets on the back -- shows the source basin of the ash, the destination or where the ash was going to be placed --

A. Yes.

Q. -- and on which day the move occurred, and the quantity of ash that was removed; that is correct?

A. That's correct.

Q. All right. Now, turning back to the front page, the colored bar chart. I put these on the screen here. And just walk through the colors a little bit for everyone. This chart was prepared by Garrett and Moore as part of their analysis of this issue. These colors represent the different locations where ash was removed from the Asheville site.

So starting on the left -- and I should note that this represents a 20 -- 2-year period. It represents from January 2015 through December 2016. Do you see those dates along the bottom of the column?

A. Yes, I do.

Q. Twenty-four months, two years, if I misspoke. And starting on the left, the blue bars, they represent the ash that was hauled from the Asheville Airport structural fill facility; do you see that section?

A. Yes, I do.

Q. Okay. And I would note that those numbers are an assumed average. Those were not included in the tracking data, but those are based on a reported 354,000 tons that were moved in the first six months of 2015 to the Asheville Airport structural fill facility. All right. And then the red bars on this chart indicate the ash that was hauled from the 1982 basin to the R&B landfill in Homer, Georgia; do you see that?

A. Yes, I do.

Q. All right. And that shows it's starting in October 2015, a small amount in October 2015?

A. Yes, that's right.

Q. And then the green lines, the large green bars, represent the ash that was ultimately hauled from the 1982 basin and stacked on site on top of the 1964 basin; do you see that?

A. Yes, I do.

Q. And lastly, the purple bars -- there are a couple other colors, but they are less important for today's analysis -- the purple bars represent the ash that was hauled from the 1982 basin to the DEC Cliffside on-site landfill; is that correct?

A. Yes.

Q. Okay. Now, there is two horizontal lines shown here and some text boxes that explain that information on the ground. Do you see the orange line on the left side?

A. Yes, I do.

Q. Now, that represents the monthly tonnage that would have been required to remove all of the ash from all of the basins, according to the original CAMA 2014 deadline, which would have been August of 2019; do you see that line?

A. (Witness peruses document.)

Q. It indicates approximately 73,000 tons per month.

A. Yes.

Q. All right. And then the black line on the other side indicates that, upon passage of the Mountain Energy Act in June 2015, the average hauling rate that would have been needed to remove all of the materials from the 1982 basin by the time the basin needed to be clean closed in September 2016 to start construction of the combined-cycle facility; do you see that black line?

A. I do see that black line.

Q. All right. So just with that general understanding, what information is presented in this table? And I know there is a lot of, kind of, moving pieces here, but a couple of straightforward questions, I think. The first is, looking at the center of the chart here where there is, kind of, an open space, why did -- why did DEP not continue to haul ash or find timely options for opportunities for hauling ash in the period of time from July 2015 until mid-October 2015?

CHAIRMAN FINLEY: Why don't we say haul CCRs just to be nice.

MR. DODGE: All right. Haul CCRs.

THE WITNESS: What would have been going on at that time with the Mountain Energy Act passage is twofold. One is contracting to have the ash starting to be moved from the '82 to the R&B, and then also that ash starting to be moved to Cliffside. So what you are, a cont -- competitive contract, you've got to get a vendor who can acquire that many trucks, that many train drivers. So when the Mountain Energy Act was passed, we weren't able to start moving ash the next day. So there is a timeline. For the ash that was going to the -- from the '82 to the '64 stack, to move 500,000 tons of ash into the '64 basin, we required a dam safety review. So we had to meet with the State, and we had to design that stack that we were going to put on the '64 basin to assure we were doing it safely. We had the appropriate setback, and it was being placed in that basin, and it would not impact the structural integrity of the '64 basin. So that's where that delay was. Do that engineering analysis, work with the State, and get an alignment of where we are going to stack that 558,000 tons. So I don't -- that gap is not, to me, unreasonable to do that engineering analysis, get approval, and move that ash into the '64 basin.

BY MR. DODGE:

Q. But prior to the passage of the Mountain Energy Act, DEP was facing an August 2019 deadline for closure of both basins; weren't they?

A. Yes.

Q. So they were already facing an aggressive time schedule for achieving compliance at this site.

Wouldn't they have had options in place

for -- wouldn't it have been prudent to have options in place for continuing to move ash in that period -- excuse me, haul CCR in that period of time between July and into November?

A. As I recall, the plan was to continue to move ash to the Asheville Airport, and there were additional phases originally planned. The airport opted, as I remember, not to move forward with those phases, and that's when they stopped and said, we are gonna stop in June of '15 with the ash structural fills at the airport. At that time, we contracted, and with the RFP process, started to look at other options to move that ash.

Q. And didn't this delay result in lost time and lost opportunities to spread out some of that truck traffic that we were discussing yesterday with Mr. Burnett that would have been -- caused congestion at the site?

A. Well, the truck traffic was purely -- I think it was the contention or the assertion by Garrett and Moore that that 558,000 tons we moved from '82 to '64 should have all went to Cliffside. We were already moving ash to Cliffside. That time between February and August we moved about 195,000 tons to Cliffside.

So we --
Q. Go ahead. I'm sorry.
A. No. So that -- would not -- actually, would have increased the impact with the ash we were already moving to Cliffside.
Q. Thinking about truck traffic -- and I'm not going to try to do any math about how many trucks or anything like that, but looking at March 2016 through August of 2016, Duke was moving each month -- most all of those months -- most of those in excess of 160,000 tons. So we were an average of 150,000 tons per month. So that's a significant amount of truck traffic on the site during those six months --
A. Yes.
Q. -- was that not the case? And have they, instead, accomplished an average of 71,000 tons per month, which would have been the number required from the passage of the Mountain Energy Act until they achieved clean closure of the '82 basin that they would have been able to reduce or spread out some of that truck traffic?
A. On the assumption that I could turn all that in one day. I can't turn that amount of trucks, that amount of drivers, that amount of logistics at the

site, to move that type of ash around, load trucks, scales, wash stations, so I could get the logistics and timing perfectly. It takes time to set that up.

Q. And as a result of some of that time, didn't DEP, instead, then have to haul a significant amount of ash, the ash shown in the green in these columns -- not just to haul, but double-handle that ash to move it from one basin to the other?

A. Well, it hasn't been double-handled yet. It had been moved over to the '64 basin. The impact would have been that many loading of trucks with the 195,000 tons we were already sent during that time period to Cliffside, add that to the 558,000 tons that Garrett and Moore asserts we should move, rough math, it shows that's probably about 40,000 loads, or loading a truck every minute and a half, loading, moving, scales, washing, getting it through the site and getting it on the highway. Virtually impossible at that site, if you've been to the Asheville site where the '82 basin is, to move that many trucks through that site and out of that basin in a minute and a half, per truck.

Q. So the only other item I would like to talk further today about is the analysis of the technical feasibility of the on-site landfill at Asheville.

A. Okay.

Q. And Ms. Townsend already -- we are done with that exhibit for now. Thank you. Ms. Townsend already asked you about this section of your testimony. Could you turn to page 15 of your rebuttal testimony, just to refresh where we are at?

A. Okay.

Q. You state on line 10, as previously discussed, that "While the CCR landfill construction had been researched in the past, CAMA and the Mountain Energy Act forever changed the technical feasibility of an on-site CCR landfill."

What do you mean by the technical feasibility in that statement?

A. Technically is building a landfill of the appropriate size that can handle 3 million tons of ash. At the Asheville site -- if you are familiar with the Asheville site -- and I know we provided drawings of the Asheville site with the combined-cycle layout, the laydown layouts, it showed where the existing power plant is, Lake Julian, and the '64 basin; there is not any other location that I can see on that map with the terrain there that you are going to build a 3 million ton landfill.

The only option would have been -- the earlier discussion in 2007 was to, as we were moving ash to the Asheville -- once we were finished with the '82 basin, with that ash going to the Asheville Airport, that would have been the opportunity to build a landfill inside the '82 basin. The Mountain Energy Act made that virtually impossible, because we were required to shut down the Asheville coal plant and build a combined cycle. If you look at the footprint of the '82 basin, the majority of that would be taken up by the combined cycle, its required facilities, and laydown area to build that plan and have it operational by 2020, January.

Q. And you included that layout in your Exhibit 4 of your rebuttal testimony; did you not?

A. I believe we did, yes.

Q. Okay. Would you mind turning to Exhibit 4, and Ms. DeSouza would put that on the screen there as well.

A. (Witness peruses document.)

Q. Do you have that diagram in front of you?

A. Yes, I do.

Q. Thank you. So when you look at the site layout shown above and on the screen here, as you were indicating, much of this is taken up by the combined cycle facility and the laydown areas that will be required --

A. Required to bring the appropriate -- to bring that heavy equipment in as we build that combined cycle.

Q. All right. And when looking at the map, the only open area that's generally open is the '64 basin; is that correct?

A. That's correct.

Q. Okay. And that basin is generally dry and has not been impounded for some time; is that correct?

A. That's incorrect. Don't forget, part of the '64 basin is what we call the rim ditch. Current ash today in a production, that ash is being sluiced to the rim ditch, which is part of the '64 basin. It is excavated out of the rim ditch, which is a concrete structure, and then moved over to the '64 basin, continued to be stacked, as well as some of that is -- and get it prepped, from a moisture standpoint -- will go to the R&B landfill. So we are still in production of ash. We will be producing ash until January 2020 going into the rim ditch, which is inside the '64 basin.

Q. Do you know how much of the '64 basin is taken up by that rim ditch, the approximate space?

A. It's hard to -- you don't have -- I don't have it outlined there, but it is the -- if you look at the -- it's hard for me to point and get that, but I could --

Q. Could you give a percentage? Just could you give an approximate?

A. I'm just looking at maybe a third is the rim ditch.

Q. All right. And also the '64 basin is where DEP chose to stack some of the ash that was removed from the 1982 basin; is that correct?

A. That is correct.

Q. All right. Can you turn to Rebuttal Exhibit Number 5 that was distributed? This is the document, Appendix A, Waste Inventory Analysis 1964 Basin. Do you have that document, Mr. Kerin?

A. Yes, I do.

CHAIRMAN FINLEY: Mr. Dodge, let's -- if it's all right with you, we will take a 15-minute recess.

MR. DODGE: I have about two minutes,

whichever you prefer.

CHAIRMAN FINLEY: Go ahead and finish.

MR. DODGE: Okay. Thank you. This will be brief.

BY MR. DODGE:

Q. So this report is dated December 2016, as printed from the -- available on the DEQ website; do you agree with that? It's part of the SARP that's filed with DEP -- I'm mean, excuse me, DEQ?

A. Subject to check. I don't have the SARP in front of me.

Q. And just briefly, turning to the second page, there is a revision log in the middle of the second page that has a -- I bracketed it -- it indicates revision 1A. Can you read that, what it says by that revision log 1A?

A. "Refined volume calculations."

Q. And the second sentence?

A. "Separated from landfill size calculations."

Q. Okay. What is the landfill size calculations that's referred to there?

A. Without having the full report in front of me, I'm not sure what the context there is.

Q. Okay. And then the third page has a similar reference to that landfill size calculation?

A. Yes.

Q. We will skip that, to the fourth page, or what is labeled as page 4 after the table of contents. I bracketed one paragraph there in the middle. Can you read that paragraph that's bracketed?

A. "Since the 1964 pond has not impounded water for many years, there have been significant dry stacking, filling of the pond. It is assumed to have properties close to those in the second row of the above table."

Q. And that second row in the above table is label CCR and ash fills; is that correct?

A. That's correct.

Q. Okay. So indicating more dry -- more character -- characteristics of a dry stack?

A. That's correct.

Q. All right. Now, at the time of the passage of Mountain Energy Act, the moratorium on CCR landfills had sunsetted; is that correct?

A. I don't have that exact date, but --

Q. Sunsetted in 2015?

A. I believe. I would have to subject to check.

Q. Okay. And that -- the Mountain Energy Act gave DEP an additional three years at the Asheville facility to complete its closure; is that correct?

A. Yes, it did.

Q. And did DEP evaluate, at that time, the feasibility of an on-site landfill in the '64 basin?

A. No, we did not, because again, that's a timing issue. We would have to excavate the ash, meet the clean closure requirements, stage that ash somewhere -- which we looked at the drawing, there was no place on the site to stage that ash -- line the basin, make it a land -- permit as a landfill, and move that ash back into that landfill. That would have been double-handling, at least.

Q. And I'm not an engineer, and I don't claim to be, but I'm always amazed at their ability to come up with some solutions to these challenging problems, but faced with the choice on hauling ash off site, and the associated impacts of local communities we've talked about, as well as potentially increasing the closure cost by orders of magnitude as we discussed with hauling off site; isn't that something that Duke should have considered?

A. Again, it was -- timing is infeasible to move that amount of ash, and again, store it somewhere on the site, which we've already determined that there is not a location on site, permit it as a landfill, lining it, and moving it all back in that time frame would not have been feasible.

MR. DODGE: I have no further questions.

CHAIRMAN FINLEY: We are going to take a recess until 3:50.

(Whereupon, a recess was taken from 3:33 p.m. to 3:50 p.m.)

CHAIRMAN FINLEY: Okay. Are you through, Mr. Dodge?

MR. DODGE: Yes. I have no further questions.

CHAIRMAN FINLEY: All right. Redirect?

MR. BURNETT: No, sir.

CHAIRMAN FINLEY: Questions by the Commission? Mr. Patterson has a question.

EXAMINATION BY COMMISSIONER PATTERSON:

Q. I want to continue what I -- questions I started with the other day about the -- who the contractors are on the CCR removal, and I have got a list here, somewhere on this stack, of the contractors that are from North Carolina, and I think one list shows roughly $162 million to some of the larger contractors, and then some of the smaller contractors, I think it's, like, $13 million. And as I understand it, there has been about a billion in spend on this whole thing, or will be. That is a horribly small percentage of that going to North Carolinians when you are expecting North Carolinians to pay for the whole thing. That desperately needs to be corrected.

And when I look and I see -- the one African-American company out here, out of all of this billion dollars or so, $200,000. That's -- I can't accept that. As my granddaddy would say, that dog won't hunt. So I need a way that you are going to correct that. And I don't need it corrected 10 years from now. I need it corrected, and I know it can be.

Many, many, many years ago, when Progress Energy was called CP&L, I had a company called Webb Patterson Communications. They hired us to -- when deregulation was supposed to happen, they hired us to help them understand how to reach out to communities that they have never reached out to before, because there was nothing to sell. Well, part of what we helped them do was change the look of the Company, period. In order to do that, one of the first things we suggested is make the Company look more like the people you are trying to serve. And this Commission, we might differ on a whole lot of things, but one thing we do know, we serve the people of North Carolina, and that is information that you should take to heart. And I need a solution. I don't know if that's a question or if that's a sermon, but I hope you heard it.

A. I understand.

Q. Thank you.

CHAIRMAN FINLEY: Questions on the Commission's questions? All right. Thank you, Mr. Kerin. We will accept your exhibits, and the cross examination exhibits that were identified in your rebuttal testimony.

(Whereupon, Kerin Rebuttal Exhibit 1 through 5, AGO Kerin Rebuttal Cross Examination Exhibit Number 1, and Public Staff Rebuttal Exhibit Numbers 1 through 5 were admitted into evidence.)

MR. BURNETT: Mr. Chairman, we will call Dr. Wright back to the stand for his rebuttal.

CHAIRMAN FINLEY: All right.

THE WITNESS: Do I need to be resworn?

CHAIRMAN FINLEY: No, you don't have to be resworn.

THE WITNESS: Thank you.

JULIUS A. WRIGHT,

having previously been duly sworn, was examined and testified as follows:

DIRECT REBUTTAL EXAMINATION BY MR. BURNETT:

Q. Good afternoon, Dr. Wright.

A. Good afternoon.

Q. Are you the same Julius Wright that provided direct testimony in this case?

A. Yes, I am.

Q. Did you also cause to be prefiled in this docket, on November 6th of this year, 44 pages of rebuttal testimony in question-and-answer format?

A. Yes, I did.

Q. Do you have any changes or corrections to that rebuttal testimony?

A. No, I do not.

Q. If I were to ask you the same questions that appear in your rebuttal testimony today, would your answers be the same?

A. Yes, they would.

MR. BURNETT: Mr. Chairman, at this time, I would move that the rebuttal testimony of Dr. Wright be copied into the record as if given orally from the stand.

CHAIRMAN FINLEY: Dr. Wright's rebuttal testimony consisting of 44 pages is copied into the record as if given orally from the stand.

(Whereupon, the prefiled rebuttal testimony of Julius Wright was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of:	)	
	)	
Application of Duke Energy Progress, LLC	)	**REBUTTAL TESTIMONY OF**
For Adjustment of Rates and Charges	)	**DR. JULIUS A. WRIGHT FOR**
Applicable to Electric Service in North	)	**DUKE ENERGY PROGRESS, LLC**
Carolina	)	

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, OCCUPATION, TITLE, AND BUSINESS ADDRESS.

A. Julius A. Wright, Managing Partner, J. A. Wright & Associates, LLC, 18 Edgewater Drive, Cartersville GA, 30121. I am a consultant to regulated utilities and regulatory agencies and other public bodies on issues related to economics, economic modeling, regulatory policy, industry restructuring, demand-side investments, and resource planning.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this rebuttal testimony on behalf of Duke Energy Progress, LLC ("DE Progress," or the "Company").

Q. ARE YOU THE SAME JULIUS A. WRIGHT WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. PLEASE DISCUSS THE PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. The purpose of my rebuttal testimony is to address several issues, discussed in the direct testimony of several intervenors, that are related to the recovery of costs associated with coal ash remediation expenses. Specifically, I will address issues raised in the testimonies of Public Staff witnesses Jay Lucas and Michael C. Maness, Attorney General Office ("AGO") witness Dan J.

Wittliff, and Carolina Utility Customers Association, Inc. ("CUCA") witness Kevin W. O'Donnell.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My testimony recommends the Commission reject the cost recovery disallowances related to coal combustion residuals ("CCR") proposed by Public Staff witnesses Lucas and Maness, AGO witness Wittliff, and CUCA witness O'Donnell. These witnesses share a common recommendation – that DE Progress should only be allowed to recover a portion of its costs to comply with state law and regulations and federal rules on CCR, but each has different theories to support their arguments. Witness Maness provides testimony to implement Mr. Lucas' recommendations. As I will explain in my testimony, their theories are unfounded and do not provide a proper basis on which costs may be disallowed.

Public Staff witness Lucas spends a substantial part of his testimony arguing that only three limited categories of costs should be excluded from DE Progress' request: $88,000 for litigation costs and settlements, $6.7 million for groundwater extraction and treatment, and federal plea agreement costs (that he admits DE Progress has already excluded).[1] However, he then summarily concludes that DE Progress should be disallowed an additional 50% of its environmental compliance costs (after taking out his aforementioned specific disallowances and those offered by Public Staff witnesses Garrett and Moore) under the assertion that DE Progress has

[1] See Lucas at pages 65 to 70.

committed and may commit violations of state environmental ground water laws. Without drawing any causal link between past and potential future ground water violations and his recommended disallowance of costs, Mr. Lucas nonetheless concludes that a 50% disallowance of DE Progress' environmental compliance costs is appropriate. Further, Mr. Lucas finds that what he terms the most "simple" and "equitable" thing to do is to disallow half of historical and future environmental compliance costs because the issues in this case are complex.[2] Public Staff witness Maness then proposes to implement Public Staff witness Lucas' proposed disallowance of the remaining environmental compliance costs through an unprecedented 28-year amortization period for DE Progress' coal ash costs, as adjusted by the Public Staff, and then by removing the unamortized amount of deferred coal ash costs from rate base.

As to AGO witness Wittliff, after spending almost all of his testimony describing reasons why he believes that DE Progress is guilty of multiple "bad acts," witness Wittliff has the single conclusion and recommendation that DE Progress should only be allowed to recover costs required to comply with the federal CCR Rule and not any costs related to the state CAMA law.[3] Mr. Wittliff makes no attempt to quantify the disallowance he is suggesting, nor does he offer any regulatory policy or logical support for his arguments. Said simply, Mr. Wittliff says nothing more than he believes that DE Progress is a bad company and because of that opinion, some arbitrary exclusion of CAMA

[2] See Lucas at page 70, line 12 and page 71, lines 3, 5, and 17.
[3] Wittliff at page 11, lines 12-15.

compliance costs, in some unknown and unquantified amount, should be disallowed. Just like the similar argument made by Public Staff witness Lucas, this argument is simply unsupported by good regulatory policy, precedent, or logic.

CUCA witness O'Donnell arrives at the same conclusion that DE Progress should be limited to recovery of only federal CCR compliance costs and, similar to witness Wittliff, makes no reasonable attempt to quantify those costs.[4] Instead, Mr. O'Donnell suggests that 75% of DE Progress' environmental compliance costs should be disallowed based on a comparison that he created (void of any attempts to make logical comparisons) of alleged national asset retirement obligation ("ARO") amounts relating to CCRs. DE Progress witness Kerin addresses the substance of CUCA witness O'Donnell's ARO comparison, but I recommend that the Commission reject any disallowance, especially one as substantial as the amount recommended by Mr. O'Donnell, that is not based on material and competent facts and evidence that have been proven and verified as mathematically correct and substantively significant. To do otherwise would constitute poor regulatory policy and would be arbitrary.

[4] O'Donnell at page 32, lines 9-11.

II. RESPONSE TO PUBLIC STAFF WITNESSES

A. Cost Sharing

Q. WHAT IS MR. LUCAS' RECOMMENDATION ON SHARING OF COAL ASH DISPOAL COSTS?

A. Public Staff witness Lucas recommends disallowing 50% of DE Progress' CCR costs (after taking out his aforementioned specific disallowances and those offered by Public Staff witnesses Garrett and Moore). He states that the "Public Staff recommends that in addition to disallowance of costs in the three categories of environmental violations, as discussed above, and the Garrett and Moore adjustments, the Commission create a sharing of remaining coal ash costs between ratepayers and shareholders." He contends the proposed sharing mechanism is reasonable "because it would be the ***simplest*** way to equitably assign responsibility for coal ash costs" (emphasis added).[5]

Q. IN YOUR OPINION, IS SIMPLICITY A PRINCIPLED BASIS FOR DISALLOWING MORE THAN HALF OF THE COMPANY'S COSTS FOR COMPLYING WITH CAMA AND CCR?

A. No. The appropriate regulatory policy for denial of cost recovery is a finding that specifically identified costs are imprudent or unreasonable. Simply relying on a "split the baby" result because facts and analysis are difficult and complex could be seen as arbitrary and capricious. Rather than do what is "simple," my recommendation is that the Commission do what is ***correct*** based on the facts, the law, and good regulatory policy.

[5] Lucas at pages 70 to 73.

Q. IN YOUR OPINION, IS MR. LUCAS' RECOMMENDATION BASED ON THE PRUDENCY STANDARD?

A. No. In fact, Mr. Lucas cannot find the Company was imprudent for what he has called "most of the coal ash related costs."[6] Nor has he made a finding that the Company's CCR costs are unreasonable. It appears that Mr. Lucas' recommendation is not based on a finding of imprudence but instead relies on a "bad actor" theory, meaning that to him, environmental compliance costs should be disallowed if he can convince this Commission that the Company has "acted poorly," but not imprudently, in its historical coal ash disposal methods.

Q. IS IT PROPER FOR THE COMMISSION TO DENY COST RECOVERY BASED ON SPECULATION OF FUTURE FINDINGS OF VIOLATIONS?

A. No. While Public Staff witness Lucas does describe a number of past environmental issues that DE Progress has had to support his "bad actor" theory of disallowing unrelated CCR compliance costs, he also appears to rely on environmental issues that may have happened in the past or could occur in the future. On numerous occasions, Mr. Lucas appears to support his recommended disallowance, in part, by discussing events that "may" occur or that "might have" occurred. For example, he states: "In summary, the federal criminal case shows actual coal ash related environmental violations at three DE Progress coal plants, the two Sutton settlements indicate ***probable***

[6] Lucas at page 62, lines 8-9.

environmental violations, and the other environmental litigation leaves open the ***possibility*** of additional environmental violations being shown either in court or through data reported to DEQ."[7] He further states "some environmental violations have been established, and others are ***likely*** to be established in the future through ongoing monitoring and assessments of ash basins."[8] Therefore, I find it troubling that Mr. Lucas bases at least part of this theory for disallowance on speculation and moreover, he has not identified what portion of his cost disallowance is based on past violations and what portion of his disallowance is based on heretofore unknown future violations.

Q. MR. LUCAS STATES THAT "... FOR MOST OF THE COAL ASH RELATED COSTS IN THE DE PROGRESS RATE REQUEST THERE IS SOME DEGREE OF DE PROGRESS CULPABILITY FOR COSTS DUE TO NON-COMPLIANCE WITH ENVIRONMENTAL REGULATIONS, BUT IT MAY FALL SHORT OF IMPRUDENCE. IN THIS SITUATION, AN EQUITABLE SHARING OF THOSE COSTS IS REASONABLE AND APPROPRIATE...."[9] DO YOU AGREE?

A. No. When Mr. Lucas refers to fines or penalties as being unrecoverable or costs that should be shared, it is my understanding that the Company has not asked for recovery of those costs. However, when Mr. Lucas recommends disallowance of 50% of the Company's costs for its CCR plans (costs, I

[7] Lucas at page 56, line 19 to page 57, line 2.
[8] Lucas at page 57, lines 16-18.
[9] Lucas at page 62, lines 8-13.

understand, of complying with laws and regulations) as "equitable," because he thinks the Company has some "culpability" for these CCR costs, I disagree. When it comes to the costs the Company incurs to meet new coal ash CCR and CAMA Rules, then his "culpability" cost recovery standard is one with which I am unfamiliar. Rather, the regulatory standard for cost recovery, including those costs related to environmental standards, is that the cost must be reasonable and prudently incurred. While Mr. Lucas cannot find the Company was imprudent for what he has called "most of the coal ash related costs,"[10] he nevertheless believes that such prudently incurred environmental costs should be disallowed through what he terms "an equitable sharing" cost recovery proposal justified as being the "simplest" approach. I do not believe this type of subjective cost recovery standard is appropriate, particularly for costs the Company is required to undertake in order to comply with environmental standards.

Q. SIMILARLY, PUBLIC STAFF WITNESS MANESS INDICATES "THE COMPANY'S FAILURE TO PREVENT ENVIRONMENTAL CONTAMINATION FROM ITS COAL ASH IMPOUNDMENTS, IN VIOLATION OF STATE AND FEDERAL LAWS, SUPPORTS RATEMAKING THAT LEAVES A LARGE SHARE OF THE COSTS FOR DUKE ENERGY CORPORATION SHAREHOLDERS TO PAY."[11] DO YOU AGREE WITH THIS CONCLUSION?

A. No, however, Mr. Maness appears to be the witness who is charged with

[10] Lucas at page 62, lines 8-9.
[11] Maness at page 16, lines 5-11.

implementing Mr. Lucas' cost sharing proposal and not the witness who is defending its substance. Accordingly all of the arguments I make in this testimony against Mr. Lucas' proposals apply equally to Mr. Maness' adoption and implementation of them.

Q. IS DE PROGRESS' EXPERIENCE WITH LITIGATION OVER ITS CCR IMPOUNDMENTS SIMILAR TO OTHER UTILITIES UNDER THE COMMISSION'S JURISDICTION?

A. Yes. It is important to discuss this issue here because Public Staff witness Lucas appears to use the Company's litigation experience as further support for his "bad actor" theory of cost recovery. It is my understanding that Dominion Energy ("Dominion"), like DE Progress, has been working with its environmental regulator, Virginia Department of Environmental Quality ("VADEQ") to address groundwater quality at its CCR impoundments. For example, in 2002 Dominion initiated a groundwater monitoring plan at its Chesapeake Energy Center ("CEC") to address groundwater protection standard exceedances of arsenic attributed to wet ash from the unlined former ash settling basins.[12] Subsequently, Dominion proposed and VADEQ accepted a Corrective Action Plan for the site.[13] In 2014, the Southern Environmental Law Center ("SELC"), representing the Sierra Club, filed suit under the Clean Water Act ("CWA") against Dominion relating to CCR

[12] Corrective Action Plan for Chesapeake Energy Center at 1 (Executive Summary) (Feb. 2008), *available at* http://www.cityofchesapeake.net/Asset13881.aspx.
[13] *Id.*

impoundments at CEC and Possum Point.[14] Ultimately, the Eastern District of Virginia concluded that Dominion violated the CWA, but that Sierra Club's proposed remedy – excavation – was "draconian" in light of the lack of environmental harm caused by the violation.[15] Instead the court ordered Dominion to implement additional monitoring and to continue to work with VADEQ to establish a closure method that does not rely solely on closure-in-place.[16] Using the Public Staff's logic, arguably Dominion's closure costs of the CEC CCR impoundments were incurred as a result of litigation over environmental violations. Subsequently, Virginia adopted the EPA's CCR Rule, which requires additional groundwater monitoring and corrective measures. Those same corrective measures, however, could have been implemented under Virginia's pre-CCR solid waste regulations. Yet, the Public Staff recommended that Dominion be able to recover CCR costs related to CEC. Therefore, it appears that Mr. Lucas only wishes to apply his new "split the baby" standard of prudence review to DE Progress and not to others that are similarly situated.

Q. IS THIS PROPOSED TREATMENT CONSISTENT WITH WHAT THE COMMISSION HAS DONE IN PREVIOUS CASES?

A. No. It is in fact inconsistent that the Public Staff did not apply this same "equitable sharing" cost recovery methodology for these same types of costs just one year ago in the Dominion North Carolina Power rate case, Docket

[14] *In the Matter of Application by Virginia Electric & Power Co.*, Direct Testimony of Paul M. McLeod at 26:8-17, Docket No. E-22, Sub 532 (Mar. 31, 2016).
[15] *Sierra Club v. Virginia Elec. & Power Co.*, 247 F. Supp. 3d 753, 757 (2017).
[16] *Id.*

No. E-22, Sub 532. In that proceeding, Dominion requested recovery of CCR Rule compliance costs up to and through 2016 and the Public Staff "investigated the CCR expenditures that the Company has proposed to defer and amortize in this proceeding, and has determined that the costs were reasonably and prudently incurred."[17] Those CCR expenditures included closure and related costs for the Chesapeake Energy Center Ash Landfill even though as noted above, a court has found past violations of the CWA at this Chesapeake Energy Center. The Commission concluded that the "recovery of the [CEC] closure costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented and should be adopted."[18] I believe the Commission's CCR cost recovery methodology in the Dominion case was correct and should be applied in the same way in this proceeding.

Q. DO YOU AGREE WITH MR. LUCAS THAT AN EQUITABLE SHARING OF COAL ASH COSTS AS PROPOSED BY THE PUBLIC STAFF IS APPROPRIATE CONSIDERING THE COMMISSION'S TREATMENT OF ABANDONED NUCLEAR PLANT COSTS?[19]

A. No, in addition to his "bad actor" theory, Mr. Lucas also attempts to support his recommended disallowance with this comparison, but abandoned nuclear plant costs are not comparable to CCR costs. In the past, abandoned nuclear plant costs were not found to be used and useful, and thus not eligible for rate

[17] *In the Matter of Application by Virginia Electric & Power Co.*, Direct Testimony of Michael C. Maness at 18:4-7, Docket No. E-22, Sub 532 (Sept. 7, 2016).
[18] *In the Matter of Application by Virginia Electric & Power Co.*, Order Approving Rate Increase and Cost Deferrals at 70, Docket No. E-22, Sub 532 (Dec. 22, 2016) ("Dominion Rate Case Order").
[19] Lucas at page 70, lines 13-16.

base type of treatment. As I discuss further below in response to Public Staff witness Maness' testimony, in the recent Dominion rate case, the Commission found that CCR repositories were and continue to be used and useful and were therefore not "abandoned."[20] Therefore, these costs are eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful utility property.

A more appropriate nuclear cost recovery example to apply in this case would be where this Commission found some costs that were due to imprudence on the part of the utility, specifically related to Shearon Harris.[21] In this situation, the Commission disallowed recovery of those imprudently incurred costs, but allowed full recovery of the remainder of the used and useful part of the Shearon Harris Plant, which was basically Unit 1 of that facility. This is exactly the treatment the Company is seeking in this case, which is full recovery of the prudently incurred and used and useful coal ash repository costs, and no recovery of the fines.

Q. DO YOU AGREE WITH MR. LUCAS[22] AND MR. MANESS[23] THAT AN EQUITABLE SHARING OF COAL ASH COSTS AS PROPOSED BY THE PUBLIC STAFF IS APPROPRIATE CONSIDERING THE COMMISSION'S TREATMENT OF ENVIRONMENTAL CLEANUP OF MANUFACTURED GAS PLANTS?

A. No. With respect to the costs associated with manufactured natural gas

[20] *See* Dominion Rate Case Order at 62.
[21] See Order dated August 5, 1988 in Docket No. E-2, Sub 537.
[22] Lucas at page 70, lines 13-16.
[23] Maness at page 19, lines 27-33.

("MNG"), I addressed the differences between these MNG costs and the coal ash costs in my direct testimony. As I explained in my direct testimony,[24] there are some distinctive differences in these two types of costs.

First, there is a significant timing difference between the actual usage of the facility and the environmental related cost recovery. The earliest North Carolina MNG cost recovery case that I could find was a 1992 Piedmont Natural Gas Company, Inc. ("Piedmont") case (Docket No. G-9, Sub 333). However, Piedmont had changed over from using MNG to natural gas in 1952, some 40 years earlier.[25] This is also the case for the Public Service Company of North Carolina, Inc. ("PSNC") MNG facilities case (Docket No. G-5, Sub 327). Therefore, unlike the current case, the MNG plants' cost recovery occurred some 40 plus years after the facilities were retired. The coal-fired generation and/or the coal ash disposal facilities are, in contrast, largely either still providing services to customers or were providing service until very recently.

Second, the coal-fired generating plants that utilized the coal ash disposal facilities have always been in the ownership of DE Progress or its predecessors. This is not the case of many MNG plants that had several owners before being acquired by the regulated gas utilities that eventually undertook the MNG cleanup. The fact that the MNG sites had multiple owners, and not just the then operating regulated gas utilities, is important

[24] Wright at page 33, line 6 to page 35, line 15.
[25] *See State ex rel. N. Carolina Utilities Comm'n v. Piedmont Natural Gas*, 254 N.C. 536, 119 S.E.2d 469 (1961).

because it means that other parties were potentially responsible parties for some of the MNG remediation costs and the utilities were apparently pursuing these claims.[26]

Finally, I am perplexed as to why the Public Staff would reach for a cost recovery example in a different industry in a case some 23 years old dealing with assets last used some 70 plus years ago when the best example of how this Commission has treated these same types of costs is the recent Dominion case that is just one year old.

Q. DO YOU AGREE WITH WITNESS MANESS' STATEMENT THAT "THERE IS A HISTORY OF APPROVAL FOR SHARING OF EXTREMELY LARGE COSTS THAT DO NOT RESULT IN ANY NEW GENERATION OF ELECTRICITY FOR CUSTOMERS?"[27]

A. No. Mr. Maness' comment regarding this Commission having a history of sharing large costs that do not result in new generation is wrong. There is no history of such sharing except in unusual circumstances, like abandoned nuclear plants that were found not to be used and useful (which is not the case as it relates to these coal ash disposal costs as I have discussed in my Direct Testimony and explain again below). However, this Commission does have a history of allowing the Company to recover what I assume Mr. Maness would call extremely large costs from ratepayers even when those costs are not the

[26] For example, Public Service has made this claim in financial filings indicating that: "The Company's actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims, and recoveries from other potentially responsible parties." See: https://www.psncenergy.com/docs/librariesprovider6/pdfs/financial-statements/3q-2009-psnc-financials.pdf?sfvrsn=2.
[27] Maness at page 16, lines 12-16.

result of new generation. Examples include other large environmental costs, the costs for transmission lines, the annual costs associated with new or upgraded distribution lines, the costs associated with system security, hurricane damage costs, and many other large costs that are not related to new generation. I know of no provision in Chapter 62 requiring different treatment for "extremely large costs."

Finally, as I noted above and discuss further below, the most relevant example of how this Commission has treated these coal ash compliance costs is the recent (December 2016) Dominion rate case.. In that case these very same coal ash related costs were allowed to be amortized over five years and allowed a return on the unamortized balance. Why, less than one year later, the Public Staff refuses to use this example of how these types of costs should be treated is curious and promotes an inconsistent, subjective, and arbitrary regulatory policy.

Q. IF THIS COMMISSION'S TREATMENT OF ABANDONED NUCLEAR PLANT COSTS AND ENVIRONMENTAL MANUFACTURED GAS PLANTS IS NOT AN APPROPRIATE EXAMPLE TO USE FOR THE RECOVERY OF THESE COAL ASH COSTS, WHAT IS AN APPROPRIATE COMPARISON?

A. As I have discussed, a straightforward example of the appropriate and consistent cost recovery treatment for these costs was the cost recovery methodology used by this Commission in the recent (December 2016) Dominion rate case, Docket No. E-22, Sub 532. In that case, even though

Dominion had been found in violation of the the CWA,[28] these very same type of coal ash related costs were allowed to be amortized over five years and allowed a return on the unamortized balance. In this proceeding, the Company is presenting the same type of coal ash related costs, yet now less than one year later the Public Staff, which agreed to this treatment for Dominion's coal ash related costs, seeks a totally different, inconsistent, and even punitive cost recovery treatment for these DE Progress coal ash costs. Further, any suggestion that DE Progress should be treated differently on the grounds that DE Progress has more costs than Dominion does not pass regulatory or logical scrutiny.

Q. ARE THE COMPANY'S COAL ASH DISPOSAL COSTS USED AND USEFUL?

A. Yes, and I disagree with Mr. Maness' contention otherwise.[29] As I said in my Direct Testimony, the coal plants associated with these costs and the related coal disposal facilities have been used and useful in providing low-cost, reliable power to North Carolina customers for more than 70 years. Consequently, these types of costs and, if any amount is deferred over time, a return would be appropriately recoverable in rates to ensure that the Company received the equivalent of the full amount of those costs.[30] As I explained in my Direct Testimony:

[28] *Sierra Club v. Virginia Elec. & Power Co.*, 247 F. Supp. 3d 753, 757 (2017).
[29] Maness at page 17, lines 7-22 and page 20, lines 15-20.
[30] Wright at page 5, lines 1-6.

> DE Progress' coal ash disposal sites have always been used and useful as part of the coal-fired generation production process. NCGS § 62-133(b)(1) provides that, in setting utility rates, the Commission must "ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, minus accumulated depreciation, and plus the reasonable cost of the investment in construction work in progress." Thus to be included in rate base, the cost must be both reasonable and incurred for property that is used and useful in providing service to customers. As discussed above and as referenced in the direct testimony of Company Witness Kerin, the Company has historically spent dollars in order to comply with the coal ash disposal regulations in effect at the time, and these dollars were a necessary expenditure related to used and useful utility costs made in the provision of electric service at the time. The Company was, and continues to be, obligated to meet the needs of its customers. This obligation to serve requires the disposal of coal ash subject to the disposal standards in effect at the time, thereby rendering the disposal sites for this coal ash, for which costs DE Progress seeks recovery in this case, "used and useful" in providing electric service.[31]

To put it another way, the costs themselves are expenditures for various expenses, including assets and equipment. However, these test period coal ash remediation expenditures are required expenditures that relate to utility plant that is still used and useful and thus are recoverable.

As I also discussed in my Direct Testimony and noted above, this Commission in the aforementioned Dominion Rate Case Order from less than one year ago has already concluded these types of costs are related to and required expenditures for assets that are and will remain used and useful. As

[31] Wright at page 25, line 11 to page 26, line 7.

that Order states:

> *"Unlike the abandoned Mt. Carmel wastewater treatment plant in Carolina Water Service, the existing CCR repositories continue to be used and useful for storing CCRs, and will continue to be used and useful until DNCP moves the CCRs to a permanent repository, or takes the necessary steps to cap and close the existing repository."*[32]

Q. DO YOU AGREE WITH MR. MANESS[33] THAT THE PUBLIC STAFF'S PROPOSED 28 YEAR AMORTIZATION AND NO RETURN ON THE UNAMORTIZED BALANCE REPRESENTS A REASONABLE AND APPROPRIATE "SHARING" OF THE COAL ASH DISPOSAL COSTS?

A. No. I understand the Public Staff's sharing proposal to be based on: (1) the Lucas simple splitting the costs argument and (2) that these costs are "extremely large."[34] I have previously addressed Mr. Lucas' argument in detail, so I will now further address the second prong of the Public Staff's argument. Again there is simply no principle in regulatory policy or the law that I am aware of that says that "extremely large costs"[35] should be somehow shared. Moreover, I am at a loss to define just what is an "extremely large" cost. Is such a cost defined by the total dollar amount, the dollars per customer, the dollars per kWh, or as in this case, is it just defined by what the Public Staff or any intervenor claims? And does the definition of "extremely

[32] Dominion Rate Case Order at page 62.
[33] Maness at page 22, lines 15-17.
[34] Maness at page 16, lines 5-16.
[35] Maness at page 16, lines 12-13.

large" costs change by utility, by year, and by the type of costs? In short, I think adopting a regulatory Order that bases its justification on a cost being subjectively and situationally defined as "extremely large" undermines the basic actual cost recovery principles embodied in North Carolina utility regulation and subjects the state's utilities to a cost recovery standard that is unknowable and ill defined. Under such a cost recovery standard, I believe that the State's regulated utilities would likely be perceived as more risky, leading to higher costs of capital. This circumstance would actually impact not only DE Progress' but all the state's electric and gas (and even water) ratepayers, resulting in higher costs for many utility services, even those unrelated to DE Progress. I do not believe such a result has been envisioned by the Public Staff, but I believe that investors would see the Public Staff's cost recovery proposal as inconsistent and even punitive regulatory treatment leading to higher cost recovery risks for all the State's regulated utilities.

Q. DO YOU AGREE WITH MR. LUCAS THAT THE COMPANY'S "FAILURE TO COMPLY WITH ENVIRONMENTAL REGULATIONS WAS UNDOUBTEDLY A CONTRIBUTING FACTOR TO ADOPTION OF BOTH CCR RULE AND CAMA?"[36]

A. No. Mr. Lucas apparently argues that Duke Energy caused or substantially caused the federal CCR Rule and the state CAMA law and thus, all CAMA and CCR compliance costs are subject to disallowance. As a prior commissioner and state lawmaker, I recommend that the Commission be very

[36] Lucas at page 72, lines 8-10.

wary of such unsupported claims. If the federal government or North Carolina had the intent to punish DE Progress, or any other company, via the CCR Rule or CAMA, they could and would have said so, but they did not. This "Duke caused the CCR Rule and CAMA" argument that the Public Staff and other intervenors are asking the Commission to adopt is not supportable by facts, and I do not support it.

To be clear, as I stated in my Direct Testimony, I believe the Dan River accident impacted the timing relative to the adoption of CAMA, but I cannot conclude that the Dan River accident modified the final CCR Rule nor can I conclude that it resulted in more strict CAMA requirements than may otherwise have occurred. With respect to CAMA, as I have stated, North Carolina has, in the past, adopted environmental regulations that are more strict than the laws in other states. Examples include the Clean Smokestacks Act passed in 2002 (ratified June 19, 2002) and the Coastal Management Act passed in 1974, the latter of which affected my legislative district when I held office. In 1983, while I was in the North Carolina Senate, the State also adopted a law dealing with development in the North Carolina mountains. Thus, I am well aware of the fact that North Carolina has taken steps to protect its environment either before, or never duplicated by, its neighboring states.

I would add that Mr. Lucas himself actually points out another example where the State of North Carolina has adopted environmental laws specific to North Carolina's needs and that these laws may be more strict than national standards, similar to CAMA and the laws noted above. Specifically, in Mr. Lucas' Direct Testimony he states that:

> *"North Carolina General Statute 143-214.1 directs the North Carolina Environmental Management Commission (EMC)* ***to develop water quality standards applicable to the groundwaters of the State*** *[emphasis added]."*[37]

Mr. Lucas also points out that these State of North Carolina groundwater standards may be more strict than national drinking water standards.[38]

These examples illustrate the fact that North Carolina's lawmakers and regulators in many cases have adopted environmental policies not only specific to the State but more strict than national or neighboring states' policies. Thus, based on my experience as a legislator and regulator in North Carolina, I believe the adoption of a state-specific CCR regulation likely would have occurred regardless of the Dan River accident.

Q. PUBLIC STAFF WITNESS LUCAS STATES THAT NO OTHER STATE HAS ADOPTED LEGISLATION LIKE CAMA.[39] IS THIS CORRECT?

A. No state has adopted CAMA; that is correct. However, it is incorrect to infer that other states have not taken state-specific actions to address CCRs. For example:

- Georgia has adopted the EPA CCR Rule, but it has additional guidelines affecting inactive facilities not covered by the CCR Rule;

[37] Lucas at page 32, lines 3-8.
[38] Lucas at page 38, lines 13-17.
[39] Lucas at page 72, lines 14-15.

- South Carolina has addressed coal ash disposal issues with a state-specific view;
- According to the Alabama Public Service Commission, the Alabama Department of Environmental Management has not yet adopted the CCR Rule but it is considering seeking EPA approval for a state program that must be as stringent as the Federal rule;
- Virginia adopted the CCR Rule and had a legislative study commission examining the issue so it would appear that additional state regulations could be possible;
- Tennessee's Department of Environment and Conservation ("Department") has adopted the CCR Rule but the Department's rule indicated that it would oversee the Tennessee Valley Authority's ("TVA's") coal ash closure and even if TVA was in compliance with the CCR that the Department may require additional actions;
- Missouri has a rulemaking underway so it is possible it could adopt standards in addition to the CCR Rule;
- Indiana adopted the CCR Rule but it already had state-specific standards in place;
- Personnel at the Texas Waste Permit Division indicated that State intends to adopt regulations, but the process will take 12-18 months;
- The Minnesota Pollution Control Agency has state-specific coal ash disposal rules;
- Wisconsin's Department of Natural Resources has undertaken a

rulemaking to promulgate coal ash disposal rules at least equivalent to the CCR Rule, although that State has not allowed CCR in unlined sites since 1988;

- The Illinois Environmental Protection Agency has had coal ash disposal standards for years, but it has undertaken a rulemaking which, if adopted, would cover closed plants.

Q. MR. LUCAS STATES HIS BELIEF THAT THE DAN RIVER SPILL LED TO CAMA AND MORE COSTLY ENVIRONMENTAL COMPLIANCE COSTS AND THAT THOSE COSTS, IN PART, SHOULD NOT BE RECOVERED FROM RATEPAYERS.[40] DO YOU AGREE?

A. No. As I have stated, it is likely the State would have adopted coal ash rules similar to CAMA and specific to North Carolina even without the Dan River accident. In my direct testimony, I explained that while I believe the timing of CAMA may have been influenced by the Dan River event, in terms of substance I cannot conclude the Legislature would have adopted anything different. Rather, even without the Dan River accident, I believe the State would likely have adopted some new coal ash disposal standards in the 2015 timeframe simply in response to the CCR Rule, as it did just a few years prior to adopting CAMA, when it adopted coal-fired generating facility environmental standards in the Clean Smokestacks Act that were more strict than the Federal standards at the time.

[40] Lucas at page 72, lines 13-15.

Furthermore, Mr. Lucas also believes that even without CAMA, the State's coal ash sites would have required cleanup costs similar to the CCR Rule and CAMA. Specifically, in his Direct Testimony, he states:

> *"Moreover, DEP's non-compliance with NPDES permits and 2L rules would in all probability have led to cleanup costs from environmental litigation or enforcement even if the CCR Rule and CAMA had never been adopted. Those cleanup costs would have largely overlapped CCR Rule/CAMA compliance costs because impoundment closure would be a primary cleanup method."*[41]

According to Mr. Lucas, these groundwater standards were initially established in 1979, long before either the CCR Rule or CAMA.[42] Therefore, according to Mr. Lucas, assuming we had neither the CCR Rule nor CAMA, the State's groundwater standards would have required coal ash disposal compliance costs similar to both. From a regulatory perspective, this would mean that the related costs to meet this 2L standard would also be recoverable from ratepayers.

I would add that regardless of whether the Company is responding to the CCR Rule standards or CAMA standards, the Company must comply with both and the related costs should be recoverable. To adopt Mr. Lucas' recommendation would be to assume that CAMA was meant to be a punitive law, which it was not.

[41] Lucas at page 72, lines 15-20.
[42] Lucas at page 32, lines 3-10.

Q. WHY IS IT YOUR OPINION THAT CAMA WAS NOT MEANT TO BE A PUNITIVE LAW?

A. CAMA was not meant to be punitive in the manner suggested by Mr. Lucas because if the General Assembly had meant this to be the case it would have indicated as much. To illustrate this point, note that CAMA did identify some very specific regulatory mandates that the Commission had to observe such as: (1) a moratorium on cost recovery related to coal ash until a specified future date;[43] (2) the potential for deferral of costs associated with coal ash disposal;[44] and (3) the identification of some specific treatment for several named coal ash disposal facilities (the high priority designated facilities).

In addition, while section 1(a) of CAMA prohibited recovery of costs "from an unlawful discharge to the surface waters of the State from a coal combustion residuals surface impoundment," G.S. 62-133.13, the legislature chose not to include groundwater cleanup costs in that prohibition. CAMA therefore does not contain any "punitive" limitation against recovery other than the provision for certain spills to surface water. Furthermore, several legislative proposals were made to further restrict cost recovery of coal ash disposal costs either under CAMA or subsequent to the law's enactment, but

[43] SECTION 2.(a) Moratorium on Cost Recovery. – The Utilities Commission shall not issue an order authorizing an electric public utility the recovery of any costs related to coal combustion residuals surface impoundments that were not included in the utility's cost of service approved in its most recent general rate case until the end of the moratorium provided in this section. Nothing in this section prohibits the utility from seeking, nor prohibits the Commission from authorizing under its existing authority, a deferral for costs related to coal ash combustion residual surface impoundments. The moratorium established under this section shall not apply to the net recovery of any fuel and fuel-related costs under G.S. 62-133.2..... The moratorium in this section shall end January 15, 2015.
[44] *Ibid.*

none were successful. For example, House Amendment 16 to CAMA, which would have prevented the Commission from allowing an electric utility to recover from retail customers costs incurred after January 1, 2014, related to the management of coal combustion residuals, was introduced but not adopted.[45] House Bill 732, introduced in April 2015 and sent to the House Committee on Public Utilities and Energy, would have prohibited recovery of all coal ash management costs, but was never considered by the Committee and thus never adopted.[46]

In addition, the General Assembly has shown it will adopt very specific regulatory mandates with other environmental laws, such as the Clean Smokestacks Act. This Act included a rate freeze, very specific tonnage levels of NOx and SO2 emissions, and mandates related to both the timing and dollar amounts that each utility could amortize during the rate freeze. In addition, House Bill 630 (Session Law 2016-95) adopted a provision related to CAMA (§ 62-302.1.(e)) that specifically prohibits the Commission from allowing the State's regulated electric utilities from recovering from retail customers the regulatory fee intended to defray the costs of regulatory oversight by the DEQ.[47]

Given the fact that the General Assembly chose to be so specific about how regulators could treat several regulatory issues pertaining to cost recovery in both CAMA and the Clean Smokestack Act, the fact that lawmakers chose

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[45] *See* H. Amendment 16, S.B. 729, 2013-2014 Leg. Sess. (N.C. 2014) (not enacted).
[46] *See* H.B. 732, 2015 Leg. Sess. (N.C. 2015) (not enacted).
[47] *See* Sess. Law 2016-95, 2015 Leg. Sess. (2016) (enacted).

affirmatively not to disallow prudently incurred costs related to CAMA, and that they chose not to adopt subsequent proposals to disallow such costs, indicates to me that CAMA was not meant to be punitive with regard to cost recovery. Rather, this indicates to me that this was an area left to Commission oversight and sound regulatory policy. Also, the very fact that CAMA allowed for coal ash disposal cost deferrals during that law's moratorium also indicates to me that the legislature envisioned that costs incurred during the moratorium, and after, related to coal ash disposal would be eligible for recovery.

B. Legal Fees

Q. PLEASE SUMMARIZE WHAT YOU UNDERSTAND TO BE MR. LUCAS' RECOMMENDATION THAT COSTS RELATED TO LITIGATION BE EXCLUDED FROM RATES.

A. Public Staff witness Lucas recommends disallowance of $88,000 in litigation defense costs in other cases where DE Progress has not been found at fault for any violation. Given the comparatively small amount of disallowance at issue under this argument, it does not warrant extensive discussion debating recovery of those specific costs. However, I believe that Mr. Lucas' recommendation impacts a larger policy issue that has far reaching implications which is why I discuss it in detail here.

As I stated in my direct testimony, DE Progress has excluded from its recovery request all fines, penalties and fees related to the Dan River event, and I take no issue with the exclusion of any litigation defense costs where DE

Progress has admitted liability or agreed to exclude them. Further, there may be cases where a company is found to be liable through adjudication where the facts and circumstances of a particular case warrant exclusion of legal defense costs. However, Mr. Lucas appears to argue that all of DE Progress' costs of defending lawsuits, whether they are found liable or not, should be excluded from recovery. It is my opinion that this position is not supported by precedent or sound regulatory policy.

Mr. Lucas argues that such costs are properly excluded from rate recovery under *Glendale* and "under the ratemaking principle that it is not reasonable for consumers to bear the costs of utility misfeasance or malfeasance." He also contends that DE Progress' settlement payments, legal fees and other costs incurred to defend two civil cases alleging environmental violations that were settled should be excluded from rate recovery, notwithstanding that DE Progress, as Mr. Lucas acknowledges, did not admit to environmental violations nor did the courts find any violations. He argues that costs for these civil cases should be disallowed because "the complaints and monitoring well data indicate substantial evidence of major groundwater contamination from the Sutton ash basins, with impacts on community drinking water supplies, and … if DE Progress did not commit the violations, it should not have made those settlement payments." This suggestion, that defending and, in appropriate instances settling, lawsuits is *per se* imprudent is not only logically contradictory (i.e. suggesting that a company may never defend itself nor ever settle means a company would be left with the choice to do nothing), it is also a suggestion of poor regulatory policy.

Q. DO YOU AGREE WITH MR. LUCAS' RELIANCE UPON THE *GLENDALE* WATER CASE FOR HIS RECOMMENDATION FOR EXCLUSION OF THE $88,000 OF LEGAL EXPENSE?

A. No. Mr. Lucas' reliance on *Glendale*, 317 N.C. 26 (1986), for disallowing costs is unfounded. First, this case pertains explicitly where the "regulated utility was penalized for violating" a rule.[48] As witness Wells explains in more detail, that is not the same kind of "violation" or permit exceedance as is the basis of the Public Staff's position here. In addition, in *Glendale*, the Court noted that Glendale did not contest the violation claimed by DHHS or the civil penalty, just the amount of the penalty. In contrast, DE Progress contested these cases. Finally, the court in *Glendale* said "these legal fees could have been avoided had Glendale initially carried out its responsibility of providing adequate water service to its subdivisions."[49] Due to the citizen suit option that was exercised in the DE Progress cases under the Clean Water Act, DE Progress could not have avoided legal fees. The Commission has also recognized that settlements and litigation defense costs, when reasonable and prudent, are recoverable costs.[50]

[48] Lucas at page 63, lines 13-14.
[49] 317 N.C. 26, 41.
[50] *See, e.g., Envirocon*, Docket No. W-1236, Sub 2 (Mar. 21, 2007); *Southern Bell*, Docket No. P-55, Sub 784 (Apr. 3, 1981).

Q. DO YOU AGREE WITH MR. LUCAS' CONTENTIONS THAT SETTLEMENTS AND CONSENT AGREEMENTS EQUATE TO ADMISSIONS OF GUILT?

A. No. Mr. Lucas' position appears to be that a utility must always litigate any challenge to conclusion, including all possible appeals, in order to be found prudent, and that entry to a settlement or consent agreement necessarily indicates liability *per se*. This is not, nor should it be, the standard for recovery of costs related to settlement negotiation. It is bad policy and short-sighted for customers. The Commission and the Public Staff have long recognized that settlements are beneficial, and not admissions of malfeasance or imprudence. As I discuss below, so have North Carolina courts and the rules of evidence.

Q. BY SETTLING CIVIL PENALTY CASES WITH THE DEQ OVER GROUNDWATER EXCEEDANCES AT SUTTON AND DAN RIVER, WAS DE PROGRESS ADMITTING LIABILITY FOR ENVIRONMENTAL VIOLATIONS?

A. No. DE Progress explicitly did not admit any liability for environmental violations in its settlements with DEQ. DE Progress and DEQ were clear in the Settlement Agreement as to why the settlement was reached: "to avoid the time and expense of prolonged litigation" and to shift the focus instead on the "assessment and, if necessary corrective action of alleged groundwater standard exceedances."[51]

[51] Sutton Settlement Agreement at 5.

Q. SHOULD DE PROGRESS' SETTLEMENTS WITH DEQ BE USED AS EVIDENCE OF ENVIRONMENTAL VIOLATIONS?

A. No. Although I am not a lawyer, I am generally familiar with the rules of evidence through my time on the Commission and the proceedings I have attended. My reading and understanding as a non-lawyer is that the North Carolina Rules of Evidence prohibit the parties from offering as an indication of guilt or of alleged environmental violations DE Progress' prior settlements. It is not just a legal matter but also a matter of common sense.

Q. HOW HAS THE PUBLIC STAFF VIEWED SETTLEMENTS IN THE PAST?

A. In other matters before the Commission, the Public Staff has vigorously defended the good regulatory policy of encouraging reasonable and prudent settlements. In 2016, North Carolina Waste Awareness and Reduction Network, Inc. ("NC WARN") filed a Petition for Rulemaking seeking to require settlements between the Public Staff and utilities to be made open to the public.[52] The Public Staff opposed NC WARN's petition, arguing that public policy favors settlements:

> [T]he Public Staff submits that settlements promote the informal exchange of ideas and information among the parties, the elimination of insignificant or noncontroversial issues ahead of an evidentiary hearing, informed decision making and the efficient administration of justice, especially in the complex matters that are typically before the Commission. Moreover, settlements result in savings to consumers by

[52] *In the Matter of Rulemaking Proceeding to Consider Proposed Rule Establishing Procedures for Settlements and Stipulated Agreements*, Order Declining to Adopt Proposed Settlement Rules, Docket No. M-100, SUB 145 (Mar. 1, 2017) ("Settlements Order").

> reducing litigation expenses that would otherwise be recoverable by utilities as a component of the cost of providing utility service.[53]

Further, in its opposition to NC WARN's petition, the Public Staff cited to North Carolina case law "touting the benefits of settlements" in business litigation.[54] The Public Staff relied on the principal articulated in *Knight* that North Carolina "law favors the avoidance of litigation, and a compromise made in good faith "will be sustained as not only based upon a sufficient consideration *but upon the highest consideration of public policy as well*."[55] Baked into many regulatory related settlements, then, is the understanding between the parties that they were entered into in furtherance of sound public policy.

Q. IS THE PUBLIC STAFF'S POSITION IN THIS CASE REGARDING DE PROGRESS' SETTLEMENTS CONSISTENT WITH PUBLIC POLICY AND ITS PRIOR POSITIONS ON SETTLEMENTS?

A. No. It is the Public Staff's position in *this* case that if DE Progress did not commit violations, it should not settle. If accepted by the Commission, this position would turn public policy and North Carolina law discussed above on their heads. I am informed that DE Progress will continue to defend future lawsuits that are filed against it. However, if entry into an appropriate settlement agreement will be viewed by itself as an admission of liability,

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[53] Settlements Order at 3.
[54] *Id.* at 3 (citing *Knight Pub. Co., Inc. v. Chase Manhattan Bank, N.A.*, 131 N.C. App. 257, 262, 506 S.E.2d 728, 731 (1998) ("*Knight*")).
[55] *Knight*, 131 N.C. App. at 262, 506 S.E.2d at 731 (emphasis added) (internal quotations omitted).

imprudency, or unreasonableness by the Public Staff or the Commission, the Company's options for either settlement or for how to defend itself will be limited, and customers will suffer as a consequence.

In addition to the policies and rules in favor of settlement discussed above, one of the policy objectives, by statute, of this Commission's regulation is:

> *"To encourage and promote harmony between public utilities, their users and the environment."*

N.C. Gen. Stat. 62-2(5). I would suggest that the Company's potential settlement of these environmental lawsuits is an outcome consistent with this policy. To summarize my position here, it is an undeniable fact that DE Progress and other electric utilities will likely from time to time continue to be sued. To suggest it is not reasonable, prudent, and in the best interest of customers to defend and, in appropriate cases, settle such suits *as a per se rule* as Mr. Lucas seems to suggest is short sighted and cannot be the basis of good regulatory policy.

Q. IN DISCUSSING POTENTIAL LAWSUIT SETTLEMENTS, MR. LUCAS INDICATES THAT SHAREHOLDERS SHOULD BEAR THE COSTS OF MAYO AND ROXBORO RELATED REMEDIAL COSTS ABOVE THOSE NECESSARY TO COMPLY WITH CAMA.[56] DO YOU AGREE?

A. No. His testimony is referring to costs related to potential settlements of coal ash disposal methods at the Mayo and Roxboro facilities. With respect to

[56] Lucas at page 66, lines 20-21 and page 67, lines 1-2.

such a settlement, Mr. Lucas' testimony as to potential Mayo and Roxboro settlements directly contradicts his testimony that "DE Progress had a duty to comply [with groundwater standards] without regard to whether they followed accepted industry practices."[57] So in this first portion of his testimony, Mr. Lucas states the Company should spend whatever is necessary so as to never have a groundwater issue. Yet later in his testimony on page 66, with regard to the potential Mayo and Roxboro settlements, if the Company agrees to a coal ash remediation methodology and costs beyond the minimum required by law, Mr. Lucas would disallow such costs, even if such a methodology is expected to be more likely to prevent future groundwater contamination.

To illustrate the untenable position in which Mr. Lucas' position places the Company, consider the Southern Environmental Law Center's ("SELC") lawsuit regarding the Mayo and Roxboro facilities, both of which are currently subject to cap-in-place requirements under the CCR Rule and CAMA.[58] The lawsuit alleges that a cap-in-place approach to unlined storage basins will allow continued contamination of groundwater.[59] Mr. Lucas states that while cap-in-place may be what is required and this is the least costly option, that such a closure method will not satisfy the plaintiffs, nor would it appear to eliminate the possibility of future groundwater permit violations.[60] On one hand Mr. Lucas claims the Company should do whatever it takes to prevent groundwater contamination, but on the other hand he claims the

[57] Lucas at page 60, lines 18-20.
[58] Lucas at page 49, lines 30-31.
[59] Lucas at page 49, lines 20-22.
[60] Lucas at page 49, lines 20-31 and page 50, lines 1-2.

Company should only do the minimum required by law even if this leads to future groundwater contamination.

These positions present DE Progress with the proverbial "heads I win, tails you lose proposition." Given this situation and the State's policy to "*encourage and promote harmony between public utilities, their users and the environment,*" my question of Mr. Lucas and other intervenors is what coal ash option should the Company undertake and which of these options would meet Mr. Lucas' and other intervenors' apparent goal of eliminating future groundwater issues and at the same time be acceptable to intervenors for future cost recovery? Mr. Lucas, along with other intervenors supporting a similar position, cannot have it both ways. If the goal is to do whatever it takes to prevent groundwater contamination, then Mr. Lucas should state this position and support any costs necessary to meet such a standard.

C. Costs to remedy environmental violations where costs exceed what CAMA would have required absent environmental violations

Q. PLEASE SUMMARIZE WHAT YOU UNDERSTAND TO BE MR. LUCAS' NEXT CATEGORY OF PROPOSED DISALLOWANCES.

A. Mr. Lucas contends that North Carolina's "2L" Rule imposes strict liability on DE Progress, thus warranting the Commission disallowing cost recovery associated with "noncompliance with environmental regulations." He then contends that because water extraction for ash basins and subsequent water treatment activities that are required under the federal CCR Rule and CAMA regulations have a "curative effect" on past alleged 2L violations, the costs of water extraction and treatment are non-recoverable. Under this strained logic, Mr. Lucas recommends that approximately $6.7 million in compliance costs be disallowed.[61]

Q. DO YOU AGREE WITH MR. LUCAS' CONTENTION THAT RULE 2L COMPLIANCE COSTS MAY BE DISALLOWED?

A. No. Mr. Lucas contends that 2L compliance is strict liability, and therefore the Company must take any action regardless of either cost or industry practices to avoid or cure such a "violation." There is no evidence that this is the intent of 2L (as discussed by DE Progress witness Wells), nor is this the reasonable and prudent standard for cost recovery. As I have stated previously, for the recovery of a cost to be disallowed, I believe the cost must be tied to some management imprudence or unreasonableness. In addition, I do not believe the Commission wants to require utilities to undertake environmental compliance projects absent consideration of the cost or of current industry practices. The absurd result from such a recommendation could be that, with any alleged or even potential violation, the Company hastily undertakes very expensive and non-standard, even experimental environmental compliance projects that could easily prove to be incredibly costly and ineffective.

[61] Lucas at page 60, lines 14-16 and page 67, lines 13-14.

Q. DO YOU AGREE WITH MR. LUCAS THAT "... MOST VIOLATIONS COULD ARGUABLY HAVE BEEN AVOIDED BY TAKING A DIFFERENT APPROACH TO ASH MANAGEMENT IN EARLIER YEARS (SUCH AS LINING THE ASH BASINS WITH IMPERVIOUS MATERIALS OR CREATING DRY STACK LINED LANDFILLS), BUT THOSE DIFFERENT APPROACHES WOULD HAVE HAD A COST TO DE PROGRESS AND THEREFORE TO ITS RATEPAYERS?"[62]

A. It is correct that at some undefined time in the past the Company, in theory, could have undertaken coal ash disposal projects above and beyond any legal requirements and much different and more costly than industry standard practices at the time. If they had, however, the costs incurred would have been subjected to high scrutiny had the Company departed from industry standards and coal ash storage methods which Mr. Kerin indicates the Company has used. In response to such increased costs, it is likely that the Public Staff and other intervenors would have accused the Company of "gold plating" its coal ash disposal facilities because such policies were beyond industry standards and legal requirements at the time. Therefore, Mr. Lucas is correct in his observations regarding the difficulty and, I assume by implication, the impropriety of using hindsight review to judge the CCR handling techniques that DE Progress used in the past. He is further correct that one may not properly disallow costs from DE Progress for actions that are

[62] Lucas at page 61, lines 8-13.

alleged DE Progress should have taken in the past without acknowledging and giving DE Progress an offsetting credit for the costs of what those actions would have required. Moreover, it is not appropriate to use the benefit of hindsight to judge whether expenditures made under the circumstances known at the time were reasonable.

For example, with respect to most of the groundwater issues discussed by Mr. Lucas,[63] at the time that DE Progress made decisions about how to address coal ash that resulted in the costs it now seeks to recover, those decisions occurred during the time period when the EPA's proposed CCR Rule was under review and while various groundwater contamination litigations were ongoing. In such circumstances, I would argue it was reasonable to wait until new coal ash disposal rules were adopted and/or litigation completed before undertaking action, which is exactly what the Company did. Neither the Commission nor utilities can see the future; the Company must decide on the best course of action based on the information it has at the time, and the Commission reviews that action based on that information. To do otherwise is not supported by North Carolina law or Commission precedent.

D. Fines & Penalties

Q. WHAT IS THE FINAL CATEGORY OF COSTS MR. LUCAS CLAIMS SHOULD BE EXCLUDED FROM RECOVERY?

A. Mr. Lucas states that costs that are required to be excluded pursuant to the

[63] See Lucas at pages 45 to 53.

probation conditions of DE Progress' federal plea agreement (fines and penalties) should be disallowed.[64]

Q. IS DE PROGRESS SEEKING TO RECOVER ANY FINES OR PENALTIES ASSOCIATED WITH ITS COAL ASH SITES IN THIS CASE?

A. No.

Q. DOES MR. LUCAS ADMIT THAT DE PROGRESS HAS EXCLUDED THESE COSTS?

A. Yes, at page 69, lines 23-25. Therefore, no further discussion is warranted on this topic.

E. "<u>Provisional" Cost Recovery</u>

Q. ~~PUBLIC STAFF~~ WITNESS MANESS STATES THAT THE PUBLIC STAFF HAS RECOMMENDED "PROVISIONAL" COST RECOVERY FOR COAL ASH EXPENDITURES PRUDENTLY INCURRED FROM JANUARY 2015 THROUGH AUGUST 2017.[65] DO YOU AGREE WITH HIS RATIONALE FOR THIS "PROVISIONAL" RECOMMENDATION?

A. No. Mr. Maness testifies that he uses the term "provisional" "because there are certain expenditures incurred during 2015 and 2016 for which the appropriateness of recovery, in the opinion of the Public Staff, may depend on the outcome of legal proceedings or other legal determinations." He states that the Public Staff "believes that the ultimate amount of 2015-2016

[64] See Lucas at pages 68 to 69.
[65] See Maness at page 10, lines 6-23.

expenditures appropriate and reasonable for recovery should await the outcome of these legal situations and further Commission scrutiny of them. Should any of these expenditures be found to be imprudently incurred or otherwise unreasonable or inappropriate for recovery, the Public Staff will propose an appropriate adjustment in DE Progress' next general rate case."[66]

It is my experience that the Commission does not approve "provisional" cost recovery. The problem with such a proposal is twofold. First, it looks like retroactive ratemaking. Second, as I have discussed elsewhere in this testimony, the utility must make decisions regarding expenditures based on the best available information it has at the time, which is the standard applied with respect to the prudence of a utility's decisions. Therefore, determinations of reasonableness and prudency of such expenditures should not depend on future outcomes of litigation or other disputes that did not inform utility decision-making, but rather should be based on what is known or knowable at the time the decisions are made, and all of my previous discussion of litigation defense costs and settlements is equally applicable here.

[66] Maness at page 10, lines 12-23.

III. RESPONSE TO AGO WITNESS DAN J. WITTLIFF

Q. DO YOU AGREE WITH AGO WITNESS WITTLIFF'S CONTENTION THAT DE PROGRESS SHOULD ONLY BE ALLOWED RECOVERY OF FEDERAL CCR RULE COMPLIANCE COSTS AND NOT ANY COSTS IMPOSED BY CAMA?[67]

A. No. Similar to Public Staff witness Lucas, Mr. Wittliff's essential position appears to be that the Company is a bad actor; therefore, it should not recover any costs associated with CAMA. I disagree.

As discussed with Mr. Lucas, there is no precedent – and Mr. Wittliff presents none, nor any regulatory policy or logical support – for denying cost recovery necessary to comply with current environmental standards simply because of a perception – whether unfounded or not – of wrongdoing. As a testament to the lack of substantive support for his arguments, Mr. Wittliff spends a substantial portion of his testimony essentially discussing why he thinks that DE Progress is a "bad actor." Mr. Wittliff ignores, however, the facts that cost recovery disallowances have to be deemed imprudent to be disallowed and that the imprudence in question has to have some causal link to the costs that are being disallowed. This is the fatal flaw in Mr. Wittliff's argument. Mr. Wittliff ignores the fact that DE Progress is not seeking to recover costs related to any fines, penalties, or costs barred from being recovered in this case. Instead, he relies on the same "Duke Energy caused CAMA and thus must be punished" argument that fails Mr. Lucas in his

[67] See Wittliff page 11, lines 12 – 15.

proposal.

Q. DOES MR. WITTLIFF MAKE ANY ATTEMPT TO QUANTIFY THE DISALLOWANCE HE SUGGESTS?

A. No, he does not. He simply suggests that DE Progress' recovery should be limited only to federal CCR Rule compliance costs, but he does not quantify what those costs are or how they should be derived. Accordingly, the Commission cannot take reasonable action on this proposal without any evidentiary basis to support the damages that Mr. Wittliff is seeking.

IV. <u>RESPONSE TO CUCA WITNESS KEVIN W. O'DONNELL</u>

Q. WHAT IS WITNESS O'DONNELL'S PRIMARY CONTENTION?

A. Similar to Mr. Wittliff, Mr. O'Donnell contends that DE Progress should be limited to recovery of only federal CCR Rule compliance costs.[68] Specifically, Mr. O'Donnell suggests that 75% of DE Progress' environmental compliance costs should be disallowed based on a comparison that he created of alleged national asset retirement obligation ("ARO") amounts relating to CCRs.

Q. WHAT IS YOUR RESPONSE TO THIS SUGGESTION?

A. Company witness Kerin addresses the substance of Mr. O'Donnell's ARO comparison, but I recommend that the Commission reject any disallowance, especially one as substantial as the amount recommended by Mr. O'Donnell, that is not based on material and competent facts and evidence that have been proven and verified as mathematically and substantively significant. To do

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[68] O'Donnell at page 32, lines 9-11.

otherwise would constitute poor regulatory policy and would be viewed as arbitrary. While I see several issues that I would have with Mr. O'Donnell's ARO comparison were I a commissioner in this matter, I defer to Mr. Kerin to address whether substantial and competent evidence exists to support his proposal.

Q. DOES MR. O'DONNELL MAKE ANY ATTEMPT TO QUANTIFY THE FEDERAL CCR RULE COMPLIANCE COSTS THAT HE CLAIMS DE PROGRESS SHOULD BE ALLOWED TO RECOVER?

A. No, he does not. Instead, he uses his 75% disallowance recommendation as what he considers a proxy of what such CCR Rule compliance costs would be. From the Commission's view, I would not accept proxy arguments for what costs "might be" when Mr. O'Donnell did not make any attempt to quantify what DE Progress' actual CCR compliance costs are.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BY MR. BURNETT:

Q. Dr. Wright, do you have a summary of your rebuttal testimony?

A. Yes, I do.

Q. Would you please now present that summary to the Commission?

A. Mr. Chairman, Commissioners. My rebuttal testimony addresses several issues related to the recovery of costs associated with coal ash remediation expenses raised in the testimonies of Public Staff Witnesses Lucas and Maness, Attorney General's Office Witness Whitliff, and Carolina Utility Customers Association Witness O'Donnell. Overall, the theories underlying these witnesses' recommended disallowances of these costs are unfounded, do not justify disallowance, and should be rejected by the Commission. The first of these proposals is Public Staff Witness Lucas' recommendation to disallow 50 percent of Duke Energy Progress' remaining coal ash costs after accounting for certain other disallowances that he and Public Staff Witnesses Garrett and Moore recommend. This recommendation does not align with the appropriate regulatory standard for denial of cost recovery, including recovery of environmental compliance costs, which is a finding that specifically identified costs are imprudent or unreasonable. Mr. Lucas did not find the Company imprudent for, what he calls, most of the coal ash-related cost, nor did he find the Company's cost to be unreasonable. Instead, he asked the Commission to disallow these costs apparently based on the theory that the Company acted poorly in its historical coal ash disposal methods and on speculation of past or future environmental compliance issues. It is not proper for the Commission to deny cost recovery based on speculation of future findings of violation. Neither is it appropriate to impose a sharing of costs based upon an undefined culpability standard.

This proposed sharing of cost is also inconsistent with Commission precedent and with the Public Staff's own position on the recovery of coal ash disposal cost in Dominion's 2016 base rate case. In that case, Dominion requested a recovery of CCR rule compliance costs up to and through 2016. Those expenditures included closure and related costs for the Chesapeake Energy Center, even though a court has found past violations of the Clean Water Act at this location. The Commission concluded that the recovery of these costs, as provided in the stipulation entered into in that case by the Public Staff and Dominion, was just and reasonable. In my opinion, the CCR cost recovery methodology applied in the Dominion case was correct and should be applied in the same way for Duke Energy Progress.

Also, the Public Staff's suggestion that the Commission's treatment of abandoned nuclear plants supports its proposed cost sharing proposal is not appropriate, because abandoned nuclear plant costs are not comparable to CCR costs. The Commission has found abandoned nuclear cost not to be used and useful, and thus not eligible for rate-based treatment. However, as I discussed in my direct testimony, the coal plants associated with these costs and the related coal ash disposal facilities have been used and useful in providing low-cost, reliable power to North Carolina customers for more than 70 years, and will continue to be used and useful. This is consistent with the recent Dominion case, where the Commission found that CCR repositories were and continue to be used and useful, were therefore not abandoned, and were therefore eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful property.

Neither does the Commission's treatment of environmental cleanup of manufactured gas plants support the Public Staff's proposed cost sharing. As I explained in my direct testimony, M&G plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental-related cost recovery, and in terms of ownership. Also, the M&G facilities, like abandoned nuclear plants, were found not to be used and useful. Additionally, I see no need to rely on a 23-year-old cost recovery example from a different industry, dealing with assets last used more than 70 years ago, when the best example of the Commission's treatment of coal ash disposal costs can be found in the Dominion case that was decided one year ago.

Moreover, the 28-year amortization period proposed by the Public Staff is not justified either by their cost sharing theory, or by defining these costs as being extremely large. Adoption of this proposal would undermine the basic cost of recovery principles embodied in the North Carolina utility regulation and would subject utilities to an unknowable and ill-defined cost recovery standard. It could also result in a perception of the State's utilities as more risky, leading to higher cost of capital and cost of service.

Turning to the CCR rule and CAMA, themselves, I do not agree, and the facts do not show, that Duke Energy substantially caused the CCR rule and CAMA and that, therefore, all costs incurred to comply with these requirements should be disallowed. As I explained in my direct testimony, while I believe the timing of CAMA may have been influenced by the Dan River accident, I cannot conclude that the North Carolina legislature would have adopted a different substantive law without Dan River. In addition, there are numerous examples of North Carolina lawmakers and regulators adopting environmental policies, not only specific to this state, but stricter than national or neighboring states' policies. Specific to coal ash, state-specific actions to address CCRs have been adopted in a number of jurisdictions. Based on all these factors, it is my opinion that North Carolina likely would have adopted a state-specific CCR regulation regardless of the Dan River accident.

It is also my opinion that CAMA was not intended to be a punitive law. CAMA does not contain any punitive limitation on cost recovery except for the provision for certain spills to surface water. Attempts to further restrict coal ash disposal cost recovery under this law have been tried three times, but in all three cases, amendments or laws to disallow cost recovery were defeated. The General Assembly has shown that it will, when it wants to, adopt specific cost recovery restrictions with other state environmental laws. An example is the Clean Smokestacks Act. In contrast, the legislature's affirmative decision not to disallow prudently-incurred costs related to CAMA, and not to adopt subsequent proposals to disallow such costs, indicates to me that CAMA was not meant to be punitive with regard to cost recovery, but rather intended to leave cost recovery determinations to this Commission's oversight and sound regulatory policy.

Turning to the issue of coal ash litigation costs, as an initial matter, Duke Energy Progress has excluded from its recovery request all fines, penalties, and fees related to the Dan River accident. However, Mr. Lucas' apparent position that all of Duke Energy Progress' costs to defend lawsuits should be disallowed recovery, regardless of whether the Company is ultimately found liable or not, is not, in my opinion, supported by precedent or sound regulatory policy. First, as my rebuttal testimony explains, the Glendale Water case does not support this theory. In addition, the Commission has recognized that settlements and litigation defense costs, when reasonable and prudent, are recoverable costs. The Commission and the Public Staff have also recognized that settlements are beneficial. The Public Staff's apparent position in this case, that, if Duke Energy Progress did not commit violations, it should not settle, is therefore inconsistent with not only public policy but also the positions it has previously taken with regard to settlements. With respect to potential settlements of coal ash disposal methods at the Mayo and Roxboro facilities, it also leaves the Company in an untenable position, since Mr. Lucas testifies both that Duke Energy Progress should spend whatever amount is required in order to never have a groundwater issue, and that, if in the course of any settlement as to Mayo and Roxboro, DEP agreed to a coal ash remediation methodology and costs beyond the minimum required by law, those costs should be disallowed, even if that methodology would be more likely to prevent future groundwater issues.

Mr. Lucas also argues that North Carolina's 2L rule imposes strict liability on Duke Energy Progress, such that the Company must take any action, regardless of either cost or industry practices, to avoid or cure a violation of this rule. He also contends that, because water extraction and treatment required under the CCR rule and CAMA have a curative effect on past alleged 2L violations, the cost of those activities, $6.7 million in this case, are not recoverable. There is no evidence that the 2L rule was intended as strict liability. Regardless, the standard for cost recovery is reasonableness and prudency, not strict liability. An adoption of the Public Staff's position would effectively require that, with any alleged or potential violation, the utility would be expected to immediately undertake remediation, regardless of the expense, and potentially even nonstandard, experimental environmental compliance projects that could not only be costly, but ineffective.

Along these same lines, while I agree with Mr. Lucas that Duke Energy Progress could, in theory, have undertaken coal ash disposal projects above and beyond any legal requirements or industry standards, those costs would have been subject to high scrutiny, and the Company likely would have been accused of gold-plating. More generally, it is not appropriate to apply the benefit of hindsight to judge whether expenditures that Duke Energy Progress made under the circumstances known at the time were reasonable.

For similar reasons, I disagree with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on their opinion that the appropriateness of such recovery may depend on the outcome of legal determinations. First, this would appear to be retroactive ratemaking. Second, again, the utility makes the best possible decisions on expenditures based on the information available at the time, and determinations of the reasonableness and prudency of these costs should not depend on future outcomes of legal proceedings but what was known or knowable at the time.

Briefly as to the other intervenors' testimony, AGO Witness Whitliff's recommendation that DEP only be allowed to recover costs required to comply with the CCR rule, and not any costs related to CAMA, should be rejected. Mr. Whitliff neither quantifies the disallowance he recommends, nor offers any regulatory policy or logical support for his position. His proposals are unsupported by good regulatory policy, precedent, or logic.

Likewise, CUCA Witness O'Donnell's recommendation that 75 percent of Duke Energy Progress' environmental compliance costs should be disallowed based on a comparison of the alleged national asset retirement obligations, or ARO, amounts relating to CCRs. The Commission should reject any disallowances, especially one as substantial as the amount Mr. O'Donnell recommends, that is not based on facts and evidence that have been proven and verified as mathematically correct and substantially significant. To do otherwise would constitute poor regulatory policy and would be arbitrary.

That concludes my summary of my rebuttal testimony.

MR. BURNETT: Mr. Chairman, Dr. Wright is available for cross.

CHAIRMAN FINLEY: Cross examination of Dr. Wright.

CROSS EXAMINATION BY MR. LEDFORD:

Q. Dr. Wright, good afternoon.
A. Good afternoon.
Q. I wanted to ask you to clarify a couple of things in your testimony. The first is on page 23 of your rebuttal testimony. You noted on line 17 and 18 that Indiana already had state-specific standards in place for coal ash disposal?
A. Yes.
Q. Do you know when those standards went into effect?
A. In 2017, the legislature adopted the CCR rules, but they already had some state-specific standards.
Q. Right. I'm asking if you know when those state-specific standards went into effect?
A. In Indiana, no, I don't have that note here. I do have the information potentially back at my hotel room, but I didn't bring those files with me.
Q. And on page 24, lines 4 through 6 --
A. Yes, sir.
Q. -- same question; you note that Illinois had coal ash disposal standards for years, quote.
Do you know when those went into effect?
A. No, I don't have that in my notes here.

Q. Can you even provide an estimate?

A. I don't remember. What I did was I did a survey of the states, both by looking at the web, and then I called the individual Utility Commissions, and then I called their Department of Natural Resources, and I have got a file on each of the states. And there are more states than this that I actually pulled, but I did look around to see what they were doing, and I just didn't bring those files with me.

Q. Okay. You were present when I asked Mr. Maness some questions yesterday, correct?

A. Yes.

Q. And the questions that I asked him were about provisional ratemaking, which you addressed in your rebuttal as well.

So before I ask you to expound upon your rebuttal testimony, can you first tell us what your definition of retroactive ratemaking is?

A. Retroactive ratemaking, from my experience on the Commission, is when you set rates this year, and then two or three years down the road, you come back and you say, wait, that rate was set wrong, and we need to refund some money to those particular ratepayers . So you are trying to go back and somehow, you know, correct a decision you made earlier.

Q. So is it your opinion that any sort of provisional deferred recovery would be retroactive ratemaking?

A. No. A deferred account recovery, if you had a true-up, could possibly be not retroactive ratemaking.

Q. Okay. So hypothetically, if the Commission were able to design some sort of deferred recovery with a true-up, would the Commission be able to take into account the outcome of lawsuits that might be relevant to those particular costs?

A. Certainly, the Commission can take into account things like that, but if they want to design a deferred account like the Company is recommending with this ongoing expense, and then a true-up every year or at some future rate case, then I would certainly support that.

Q. Given your policy background and your experience as a former Commissioner, if the Commission wanted to have Duke retain some of the risk of the insurance coverage litigation that we have been addressing during various phases of the hearing, would there be a mechanism available to them to do that?

A. I'm trying to recall where we had issues, and I just don't know how that would work or why it would be appropriate. I'm not sure why the Company should retain a risk for insurance litigations. That, to me, is unclear from my regulatory experience.

Q. Well, let's try it this way. Let's assume that ratepayers had been reimbursing the Company for the cost of insurance coverage for years and years, and there was $2- to $300 million of insurance coverage available to handle coal ash disposal liabilities, but the Company failed to timely file a lawsuit, meaning they effectively committed malpractice and didn't satisfy the statute of limitations. Who should bear the risk, in your opinion, of that outcome?

A. Well, what you're describing is a situation where the Commission has authority to look at the prudence of costs that were incurred, and that is a specific determination that the Commission has to make. It's not necessarily restricted to insurance, but it's with regard to cost. And if you think about that, you can go back to that decision tree analysis that I talked about earlier where you start with, are these costs prudent and reasonable? So I don't know that that addressed your particular question, but that's --

the Commission has authority to look at costs that were incurred.

Q. Right. But if they wait for the outcome of the lawsuits to determine whether Duke acted prudently with regard to handling the claims, would there be some risk of them engaging in retroactive ratemaking in the absence of some sort of provisional preferred recovery, in your opinion?

A. If the Company filed a rate case, and in that rate case were costs associated with litigation fees of the -- of these insurance policies, then at that time, the Commission looks -- can look at those litigation fees and determine if they were prudent and reasonable, just as they can look at any expenses during a rate case for what the Company files.

Q. I'm not referring to the litigation expenses. I'm referring to the potential loss of the $2- to $300 million in insurance coverage.

How would the Commission address that?

A. Well, I don't think that the Commission would be able to find something that the courts didn't find. If the court said one thing about the cost, in terms of insurance, I think that the Commission looks at the expenses that the Company puts before it in a rate case and determines if those expenses are reasonable and prudent. Now, if there is a settlement and somebody says, well, that settlement is not enough, then I guess that would be a situation with what I'm not -- I'm not familiar with how the Commission would handle that. I'm sure that that would be something they could look at, but I -- I just didn't have that experience when I was a Commissioner, and I haven't seen it anywhere.

Q. Do you have any understanding as to whether Duke's federal criminal pleas will have any effect on the insurance coverage or its ability to recover under their insurance policies?

A. I do not.

MR. LEDFORD: I don't have any further questions.

CHAIRMAN FINLEY: Ms. Lee?

CROSS EXAMINATION BY MS. LEE:

Q. Good afternoon, Dr. Wright.

A. Hello.

Q. Nice to see you again. Just a couple of questions.

You have criticized Mr. Lucas' recommendation of sharing coal ash costs between ratepayers and shareholders, right?

A. Yes. I criticized his methodology for getting there.

Q. In particular, his pointing to the simplicity of a 50/50 split, right?

A. Yes.

Q. Okay. But you would agree with me, right, that, under North Carolina law, rates must be, quote, fair both to the public utilities and to the customer?

A. That's true. But let me -- let me explain how you get to that point. And I discussed this, I guess it was yesterday. When you look at costs, you have this decision tree, and in that decision tree you start off, is the cost reasonable and prudent in providing service to the ratepayers? If the answer is yes, then you say, okay, is it used and useful? If the answer is yes, you go down that line, and then you say, okay, this cost is recoverable. And if it's a cost that earns a return, it earns a return. Now we come to where you are, and you say, okay, what is fair and equitable? And down there at the bottom, the Commission has some leeway. The costs need to be recovered, should be recovered, they are reasonable, prudent, used and useful, so they are recoverable. The Commission down there, at the bottom, though, can look at rate design, they can look at timing, like the timing of the recovery of costs, they even look at the timing of depreciation. And in other cases, they even can look at ROE, but this ROE has been settled. And that's where you begin to look at the fair and reasonable and the equity argument.

Now, if you go the other route and you say, okay, it's reasonable and prudent but not used and useful -- this was the Sharon Harris case. We had an abandoned plant. It was no longer used and useful. At that point, the Thornburg case looked at three options the Commission had. The costs were still recoverable, but the Commission had an option on the return allowed. Some return, no return, all return. And that gets into your equity argument again in fair and reasonable rates. The Commission has some authority there.

Now, when you talk about Lucas and what Mr. Lucas has suggested, you don't even get to the prudence or reasonable standard. You are somewhere out here. And you are saying, well, these costs are large. Let's just simplify it and split the baby. I've never heard anything like that. I mean, that's a cost recovery pare down with which I am totally unfamiliar. And I have testified in a number of rate cases in a number of states, and that's a new one on me.

Q. But you would agree that this Commission has discretion with respect to fairness and how to -- how to split up the recovery of costs?

A. That's what I am saying. When you get down to that level, they can do it with a rate design, issues and stuff like that, and the allocation of revenues. Yes, they can.

Q. And at that level -- is it -- am I understanding that explanation, that at that level they don't have the discretion to do a ratepayer/shareholder split?

A. By that -- by the normal methodology that I am familiar with, when you get to the -- past the used and useful and the -- this is a prudent and reasonable cost, then the equity argument, you look at the timing of the recovery of the cost, and you look at things like depreciation. But once you have said these costs are reasonable, prudent, and used and useful, the Commission can't just arbitrarily -- or at least in my experience -- say, well, now we are gonna still disallow some of these costs. That's not a standard with which I am familiar.

Q. Okay. Thank you. If we could turn to

page 16 of your rebuttal, please. You have drawn a comparison between this case and the Dominion rate case. If you could read the sentence that starts at the very bottom of that page, line 23, starting, "In that case," and continuing on to the next page, please.

A. "In that case, even though Dominion had been found in violation of the Clean Water Act, these very same type of coal ash-related costs were allowed to be amortized over five years and allowed a return on the unamortized balance."

Q. Thank you. And Dominion was found in violation of the Clean Water Act in March 2017; isn't that right?

A. Yes, it was.

Q. So that would be after this Commission's decision in the Dominion rate case; is that right?

A. Actually, Chesapeake had a groundwater exceedance violation in 2002, Possum Point had a clean water violation, and in 2000 -- in the 2007 EPA study about proven damage cases of coal ash -- this was right prior to the 2010 CCR proposed rule -- there was a table in there, Table 2, Virginia Power Company at both Possum Point and Chisholm (phonetic spelling) had proven damage cases. So it's not like there wasn't evidence and information out there that people could have accessed to say, well, wait a minute, you know, there are other cases that other utilities, including Dominion, have had some exceedances or violations. It's not like it was just -- this was the only case ever in history for them.

Q. Okay. My question is about the sentence, though, in your footnote 28, which cites to the 2017 decision.

That decision did come after this Commission's order, right?

A. It did.

Q. Okay. So the finding that that court made was not something that this Commission considered when it granted Dominion's cost recovery request?

A. You are correct, but they can consider that order in this case.

Q. Okay. Dr. Wright, you talked a little bit about manufactured gas plants, and if I'm understanding your testimony properly, one of the differences you note between the cleanup of those sites and coal ash cleanups is that manufactured gas plants -- or in the case of manufactured gas plants, there were multiple owners over the course of history, so there was -- the utilities were pursuing claims against other parties; is that fair?

A. Yes. And I think the case I cite was a public service of North Carolina -- I think it was public service of North Carolina, my direct testimony. It wasn't just there were other owners, they were joint owners. I mean, other owners hadn't disappeared. They were still on part of the property.

Q. So they were fighting over whose responsibility it was to clean this up or prepare for the cleanup?

A. Yes.

Q. Okay. And is Duke pursuing claims against insurance companies for its coal ash cleanup costs in this case?

A. That is my understanding, yes.

Q. Okay. And Dr. Wright, is it your opinion that the Dan River spill didn't cause the passage of CAMA, but that it did have an impact on the timing of that law?

A. I think there is no question that Dan River, you know -- it did spur the legislature to act; there is no question about that.

Q. Okay. And you have stated in your rebuttal that, even without Dan River, either CAMA or some other coal ash disposal regulations would have come into play in this state in the 2015 time frame; is that right?

A. Yes, I do.

Q. Okay. And would you think that, without Dan River, North Carolina lawmakers and regulators would have been more likely to wait and see where the EPA came out on these issues before passing their own regulations?

A. They would have probably waited until after the CCR was adopted in 2015, but all you have to do is look at the states right around us. And as I explained, I guess it was yesterday, Georgia has now adopted the CCR. In my discussions with them, they have actually gone past the CCR and adopted some rules that have -- that impact landfills that are not covered by the CCR. In Virginia, they have adopted the CCR, but the legislature passed a bill and said don't do anything right now. They required the DEPCO to -- Senate Bill 1389 required -- or 1398 required DEPCO to do a study of coal ash and what it would cost, and they said our Department of Natural Resources do nothing until after the 2018 legislative session, because Virginia wants to look and see if they want some state-specific laws. In Tennessee, the other contiguous state to North Carolina, the department there adopted the CCR, but in their specific rule it says that, when you file your plan with our Department of Natural Resources -- I think it might be the Department of Environmental Quality there -- that when you file your plan, if we don't like it, we can and will require you to go beyond what the CCR does.

So when I look at what these other states are doing, and having lived and served in the legislature of North Carolina, I think for sure that our state would have done just exactly what our neighboring states are doing, looked at North Carolina and said okay, what do we need specific to North Carolina? They did it with the Clean Smokestacks Act, they did it with the Coastal Area Management Act, they did it with the Ridgeline Law, so it would -- I mean, I just have to conclude we would not have sat on our hands and done nothing in North Carolina.

Q. Okay. And those states you mentioned: Georgia, Virginia, Tennessee, and others, the actions they have taken or are under consideration now, those all followed the finalization of the federal rule; is that right?

A. They -- pretty much in 2015.

Q. Okay. And Dr. Wright, were you here earlier today when Mr. Dodge and Mr. Kerin were having a discussion about the timing of closure at Sutton and Asheville?

A. I heard that testimony.

Q. Okay. So if Dan -- if the Dan River spill had not happened, would you agree that Duke probably wouldn't be on the same exact timelines? CAMA would have been passed in September 2014, would have waited until 2015 for some kind of regulation, and then whatever requirements would have unfolded at that point; is that fair?

A. It's fair, but you also have to know how the legislature works in North Carolina, and if it's 2015, I think would have possibly been when they would have acted.

Q. Okay. And is it possible that the actual closure timelines would have been different if Dan River hadn't happened and the legislature had waited until after seeing the federal rule?

A. Well, it's possible.

Q. Okay.

A. But I actually talked to Mr. Kerin about this, and he told me a couple of things. He said, first, some things under the CCR are sooner than CAMA, some are later than CAMA. I suggested, if you want to know the exact dates, maybe Mr. Wells would know those.

Q. So it's possible, then, that the CCR rule would have required closure earlier, and then in that respect, been more stringent?

A. If -- you know, I don't know those details. Mr. Kerin would have been the person to ask, but he -- I did ask him, and he said some of the dates are sooner, some are later.

Q. All right. That's fine. Last question.

Dr. Wright, during your time with this Commission, did you have any occasion to specifically review the Company's handling of coal ash?

A. We had rate cases on a frequent basis. I would assume that, within those rate cases, we had some issues related to the cost associated with coal ash, but it was not anywhere like what we are doing now. So did I review the coal ash ponds and stuff? I can't say that I did. Were there costs that somebody had as a line item? Possibly.

MS. LEE: Okay. Thanks. Nothing further.

CHAIRMAN FINLEY: Who is next? Anybody?

CROSS EXAMINATION BY MR. DROOZ:

Q. I think there is light at the end of the tunnel.

Dr. Wright, would you agree that Duke Energy Progress is responsible for compliance with environmental laws and regulations that apply to its ash basins?

A. Yes, they are.

Q. Are you aware that Duke Progress' ash basins have been involved and caused exceedances of groundwater quality standards at all eight coal-fired power plants in the Carolinas?

A. I know they have had exceedances, but how many and which, you should ask Mr. Wells.

Q. Are you aware that Duke Progress has unauthorized discharges from its ash basins to surface waters in violation of state and federal laws?

A. I'm aware that they have had those, but you will need to talk to Mr. Wells about specific ones.

Q. We will talk later with Mr. Wells, but I want to pursue this a little bit more.

MR. DROOZ: At this point, we would like to pass out a couple of exhibits that go together.

One is the environmental audits conducted by consultants for Duke Progress and the court-appointed monitor, and the other is the federal court judgment. We will ask that the federal court judgment be marked for identification as Public Staff Wright Rebuttal Cross Exhibit Number 1.

CHAIRMAN FINLEY: This document shall be marked for identification as Public Staff Wright Rebuttal Exhibit Number 1.

MR. DROOZ: And that the second packet of documents, which are environmental audits, be marked for identification as Public Staff Wright Rebuttal Cross Examination Exhibit Number 2.

CHAIRMAN FINLEY: Hold on a minute. Which one do you want 1? Only thing I --

MR. DROOZ: The federal judgment.

COMMISSIONER CLODFELTER: What's been passed out I think is what you want Number 2.

CHAIRMAN FINLEY: I think I got Number 2 first.

MR. DROOZ: Okay. We will make sure everybody's got both before we proceed. I just thought it would be easier to hand out a couple at a time rather than get up and down.

COMMISSIONER CLODFELTER: Mr. Drooz, do you want Number 1 to be the coal -- CCR rule?

MR. DROOZ: No. It is not -- it should be the federal plea agreement, not the CCR rule.

UNIDENTIFIED FEMALE: I apologize. They are misnumbered. I'm sorry.

CHAIRMAN FINLEY: Hold on a minute. Hold on. I'll give it back.

THE WITNESS: Do I have to give it back?

MR. DROOZ: If you want to keep that as a souvenir, you are welcome to it. And by way of explanation, I will note that parts of the federal case -- the criminal case have been handed out as prior exhibits. You know, I looked at this, and when Duke Energy Progress -- found there were three distinct parts and not all of them had been handed out, so I put them together as a package.

BY MR. DROOZ:

Q. While these are being handed out, I will just, Dr. Wright, submit to you that the environmental audits are posted on Duke Energy's website and were downloaded from there. The first one, I printed out the entire one for Asheville 2016. The others I just printed out excerpts. We can provide the full ones if anyone wants them, but I just wanted to combine --

A. I think I have the environmental audits.

CHAIRMAN FINLEY: We will mark this judgment in criminal case, the United States District Court, Eastern District, Public Staff Wright Rebuttal Exhibit Number 1.

MR. DROOZ: Thank you.

CHAIRMAN FINLEY: Public Staff Wright Rebuttal Exhibit Number 1. And the environmental audit, Public Staff Wright Rebuttal Exhibit 2.

(Whereupon, Public Staff Wright Rebuttal Cross Examination Exhibit Numbers 1 and 2 marked for identification.)

BY MR. DROOZ:

Q. Do you have those in front of you now, Dr. Wright?

A. I have this judgment, and I have the environmental audit report.

Q. Okay. And I will submit to you that the judgment in Cross Exhibit 1 here is that -- there is three parts to it. The first is the actual court judgment, and then the second is the memorandum of plea agreement, and the third part is the joint factual statement.

And I wanted to ask you, on the judgment, it's I believe numbered pages 1 through 14 at the bottom.

A. Page 14 at the bottom?

Q. Well, the judgment, the top document, is numbered pages 1 through 14.

A. Okay.

MR. BURNETT: Mr. Drooz, it may be helpful to tell Dr. Wright to disaggregate these. I think he's getting confused by --

THE WITNESS: I got them.

MR. BURNETT: Take them apart, maybe.

THE WITNESS: Okay.

BY MR. DROOZ:

Q. Okay. And if you will turn to page 9 of 14, and there is a paragraph 2C there.

A. (Witness peruses document.)

Q. These are just foundation questions, because I don't know that the witness is familiar with the environmental audit. So in paragraph 2C there, indicates that the CAM, which if you will accept subject to check, stands for court-appointed monitor, shall establish a schedule for conducting environmental audits for each of the defendant's coal ash impoundments on an annual basis; do you see that?

A. Yes, sir.

Q. Okay. That's a condition of probation. Without belaboring it, there is a similar statement in the memorandum of plea agreement at page 28 that provides for environmental audits?

A. Yes.

Q. And that brings us to the environmental audit exhibit. Okay. If you will, turn to the first page there, and you will see that it says, "Environmental audit in support of the court-appointed monitor, Asheville steam station," and what's the date on that one?

A. June 2016.

Q. Thank you. And if you will turn in this to, it's paragraph 3.1 and it's on page 3-1.

A. Okay.

Q. And in the center of that page there is a finding by the auditors. Would you read that beginning paragraph in the finding?

A. "The auditors reviewed documentation of seeps located west of the 1964 and the 1982 ash basins, which contain pollutants and which discharge from point sources through discrete conveyances to waters of the United States. These seeps are not authorized by a current NPDES permit, and therefore constitute violations of the Clean Water Act and the NDEQ NPDES permitting program. Five seeps were identified by the audit team in their review of available documentation."

Q. Thank you. Moving on to page 3-3, would you please read the finding in the center of that page?

A. "Finding. Constituents were documented which exceeded the standards of the class GA waters established in 15A NCAC 2L.0202 in monitoring wells located at or beyond the compliance boundary for the active ash basin. Based on groundwater monitoring analysis completed, exceedances of the 2L standards have been identified at several locations outside of the compliance boundary for the active ash basin. The locations for the 2L exceedances are shown on Attachment C. Nearly the entire western leading edge of the plume is identified above 2L standards. The parameters with exceedances of the 2L standards include boron, iron, manganese, pH, and total dissolved solids, TDS. The groundwater monitoring data establishes a reasonable technical certainty that CCR impacts to groundwater exist above groundwater conditions."

Q. Thank you. Now, on this Asheville 2016 report, the very last page is something entitled "Duke Energy actions to resolve audit findings," and if you will turn to that, please?

A. What page is that?

Q. It's the very last page of this Asheville 2016 group of documents.

A. I have got an attachment. Is that the end of the attachment or before the attachment?

Q. I don't know how they are put together in the group that you have. If you want, I can show you a copy of this. I have been told it's the last page.

CHAIRMAN FINLEY: Do you have a page number at the bottom of it?

THE WITNESS: Duke Energy's actions to resolve, dated 12/6/2016? Date of final report, 6th of June, 2016; is that what I'm looking at?

BY MR. DROOZ:

Q. Yes, sir.

A. Okay. I have got it.

Q. Okay. And are you aware that it's standard convention, when an entity has been audited, that normally they respond to the audit, provide a response?

A. Well, based on my work as an engineer in process engineering, if we got audited, then we would usually file a response.

Q. Okay. And I will submit to you that these Duke Energy actions to resolve are their responses to the audit findings. In the left-hand column you will see a summary of the findings. In the right-hand column you will see Duke Energy actions to resolve.

Do you see those headings on this page?

A. Yes, sir, I do, and my -- here's my concern. You are asking me about things, number one, that Mr. Wells -- he lives with these and is very familiar with these. He can answer that. Number two, is you're talking about seeps, and it was from 1964 to 1982. And it's almost like we have two different stories people are telling here. On this side, I'm hearing the story and your witness talk about that the Company should do something in the 1970s totally different from industry experience, and that that would have solved the problems of today, regardless of the fact that it was outside anything any other utility was apparently doing or most utilities were apparently doing, and that is one story I'm hearing. And that story must assume that the regulators -- any of the natural resources regulators were asleep, that this Commission was asleep. That during the 1970s and while these seeps were going on from '64 to '82, that the regulators and the scientific community knew nothing about coal ash disposal.

Now, the other story is, as Commissioner Brown-Bland indicated, that over time, the scientific community and regulators have been awake and have been looking at coal ash. There was the '87 EPA report, the 2007 EPA report, and by 2010 the EPA said we need to start doing something else with coal ash. And that it was an iterative process getting there. And that's where we are today. And when I hear about the seeps, and exceedances, and violations, first, you have to be very careful when you use those terms. You can talk to Mr. Wells about that. But second, I think that what we have to look at is this idea that, in the '70s, the Company could have done something, and you wouldn't have these seeps today. Well, you're -- I mean, that's, you know, a 20/20 hindsight, and it has nothing to do with the reality that we were facing at the time in the 1970s or the 1980s.

Q. And, Dr. Wright, we may have more agreement here than we realize. The Public Staff is not submitting its position as a prudence evaluation;

rather, our concern was about compliance versus noncompliance with environmental violations, and that's why I'm asking you about these audits. If you look at this Duke Energy action to resolve, the first sentence in that summary of findings. As I read that, it says, "Discharges via seeps are occurring." This isn't about something in the distant past. This is at the present. And then it indicates, "The Company has submitted applications to try to get those qualified under the NPDES permits"; is that correct?

A. That's correct.

Q. Okay. Now --

A. You say it's occurring now, but where you told me to look at the five seeps in this document, it said it occurred from 1964 to 1982, what I quoted, because I wrote down that. I was surprised.

Q. Let's go back to that page 3-1. I know this is kind of rushed. You haven't had time to digest that. So if we go back and take a look.

A. (Witness peruses document.)

Q. Are you there?

A. Yes.

Q. And it says, "Seeps located west of the 1964 and 1982 ash basins." Those dates reflect the date the ash basins were created, don't they, not the date of the seeps?

A. I have no idea. I don't know when they were created. Its says seeps located west of the '64 and 1982 ash basins.

Q. Okay. And if you look at that paragraph --

A. Okay. I see what you are saying. Yes, that could be seeps. I could have read that wrong.

Q. If you look at the heading on that paragraph number 1, it says, "Seeps are present at the facility"?

A. Yes, that's what it says.

Q. Okay. Thank you. I'm glad we --

A. I'm sorry I read that wrong.

Q. So if we turn back to the Duke Energy's action to resolve and we look at the right-hand column --

A. Yes.

Q. -- and the third item down there -- I will just read this rather than have you go through the exercise here, and you tell me if this is a correct reading. "Concentrations of ash-related constituents were documented that exceeded the standards for class GA waters in monitoring wells located at or beyond the compliance boundary for the active ash basin. Duke

Energy is in the process of addressing groundwater impacts at Asheville under the procedures set out in the Coal Ash Management Act, including the generation submission to NCDEQ of a comprehensive site assessment and a two-part corrective action plan."

Is that a fair reading of that?

A. Yes.

Q. Okay. And so that indicates that -- and I'm asking this. Does it indicate to you that the Company has accepted the finding that there is exceedances there, that they need to be corrected, and the remedial action will occur under the CAMA corrective action plan?

A. I'm not sure if I can agree with your characterization that the Company has accepted the findings. That's something you need to talk to Mr. Wells, because I think that becomes more of a legal type of analysis, and that I don't know.

Q. Do you see anything on this page where the Company challenges the finding that there is exceedances that -- of ash-related constituents beyond the 2L standards at or beyond the compliance boundary? Does the Company challenge that anywhere on this page?

A. Well, I haven't read the whole page, but I don't know that they have or have not challenged it. Again, Mr. Wells deals with this on a day-to-day basis. So he would be the person you could ask on that one.

Q. Okay. So there is environmental audit reports -- I'm looking at the clock here -- for all eight of the plants in the Carolinas. There is a set for 2016 and another set for 2017. We can go through them one by one and talk about the question of whether there was compliance or noncompliance as shown by these environmental audits, or if you prefer to shorten this a little, we can accept, subject to check, that these reports show groundwater exceedances caused by ash basins at every Duke Energy Progress coal-fired generating station in the Carolinas, and also unlawful seeps at most of them.

Will you accept that, subject to check, as being shown in these environmental audit reports?

A. I will accept that these reports say what they say, but you need to ask Mr. Wells about those. But, as I said yesterday, the fact that the Company has an exceedance or a violation is not indicative or necessarily in any way at all tied to the cost that they are asking for now. If the Company has a violation and has admitted wrongdoing, then those costs, the fine, whatever, I don't think they should be able to recover. But that's totally different from the Company having to comply with new regulatory standards. It is my understanding that the Company is not asking to recover fines or anything for which they have said they were guilty. But in terms of the cost associated with the new regulations, those are what I would say are long-term compliance costs. That's what we are talking about here today, in my opinion. Those are the costs that the Company has asked to be recovered in this case.

Q. And what if there are costs to remediate violations of standards that existed before CAMA and the CCR rule; should the Company be allowed to recover 100 percent of those from ratepayers?

A. I think it's a fact-based analysis. You have to ask yourself, if those costs are related to the Company saying that we were guilty, we knew this, we should have known it. In that particular situation, then you -- then I could say there is an argument no, but you have got to have wrongdoing. When you get to costs like this, the Company has to have some knowledge of wrongdoing and admit it.

Q. So if the Company has violated laws but does not admit it, are you saying there is no wrongdoing, and therefore they get to recover everything?

A. No. If they were found guilty in a proceeding, then I would say that's -- that's another case.

Q. So there is one more of these I want to pull your attention to. It's the second to the last. It involves H.B. Robinson, April of 2017, and I just wanted to point this one out because I think, really, none of the evidence previously had talked about exceedances at the Robinson plant.

Are you aware if Robinson is located in South Carolina?

A. Yes.

Q. And so that will have a different set of environmental regulations than North Carolina plants on the state level?

A. On the state level.

Q. Thank you. Okay. If you will let me know when you are at that.

A. I'm there.

Q. Okay. If you turn to page 3-1.

A. Okay.

Q. And there is a finding here also. And if you go down to, I guess it's the third sentence, it starts, "Based on the audit team's review"; if you'll read that sentence and the next sentence, please.

A. "Based on the audit team's review of the facility's 2016 NPDES goundwater sampling data, water beneath and near the ash basin currently exceeds the South Carolina class GB water classification standard for arsenic. Recent sampling in well MW-7 identified concentrations of 144 micrograms," I think that's what it is, "per liter of arsenic during the January 6, 2016, sampling event, and 140 micrograms per liter of arsenic during the July 13, 2016, sampling events."

Q. And the next sentence indicates the regulatory standard is 10 micrograms per liter?

A. Yes, sir.

Q. Okay. Thank you. All right. I think we are through, at least maybe until Mr. Wells shows up, if he wants to talk about, with this exhibit. I wanted to turn to your testimony, page 12.

A. Okay.

Q. Your rebuttal testimony. And if you will look down about lines 11 and 12, I believe Ms. Lee asked you about this earlier, or someone did. "I believe the Commission CCR cost of recovery methodology in the Dominion case is correct and should be applied in the same way in this proceeding," and that's your opinion and recommendation?

A. Yes, sir.

Q. Okay. Are you aware of the methodology in the Dominion North Carolina Power rate case included deferral of future CCR costs for determination in future cases and not a run rate?

A. Yes. I was not saying, on this particular case, that the run rate should not be included. I think the run rate is a reasonable thing to do.

Q. Okay. So you are going to modify your rebuttal testimony a little bit in that regard?

A. In that regard.

Q. Okay. Pages 12 and 13 there, you talk -- again, this has been touched on briefly -- about -- as I understand your testimony, it said abandoned nuclear plant costs were not used and useful, and therefore not eligible for rate-based treatment; is that correct?

A. Yes, sir.

Q. And you say that's not at all comparable to CCR costs. You are saying CCR costs are used and useful?

A. Yes. And the Commission said that too in the Dominion case.

Q. Is it your position that the CCR costs requested for recovery by Duke Energy Progress in this case are eligible for rate-based treatment as used and useful property?

A. They are eligible for treatment, I think what they call asset retirement obligation. They are used -- but they do represent costs that were incurred for utility property that is used and useful.

Q. I'm not sure if that's a "yes" or a "no." Can you elaborate?

A. Well, I guess this goes to the difference between Mr. Maness and I. As I understand, he's talking about accounting and various accounting mechanisms and how this would be handled. What I'm saying is that, from a regulatory policy standpoint, what the Company has spent is dollars expended on utility property that is used and useful. They should be allowed to recover that property -- I mean, those costs. If you recover them over time, then you amortize those costs, and you earn a return on those costs.

Q. If the Commission allows it?

A. If the Commission allows it, certainly.

Q. Okay. Thank you.

MR. DROOZ: That ends that line of questions. I have a bunch more I can start on, or we can close the day; as you prefer, Mr. Chairman.

CHAIRMAN FINLEY: We will mercifully close for the day. Come back 9:30 tomorrow.

(The hearing was adjourned at 4:57 p.m. and set to reconvene at 9:30 a.m. on Thursday, December 7, 2017.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appears in the foregoing hearing were duly sworn; that the testimony of said witnesses was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to this; and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 10th day of December, 2017.

NDTCA Signed Electronic Transcript

Joann Bunze

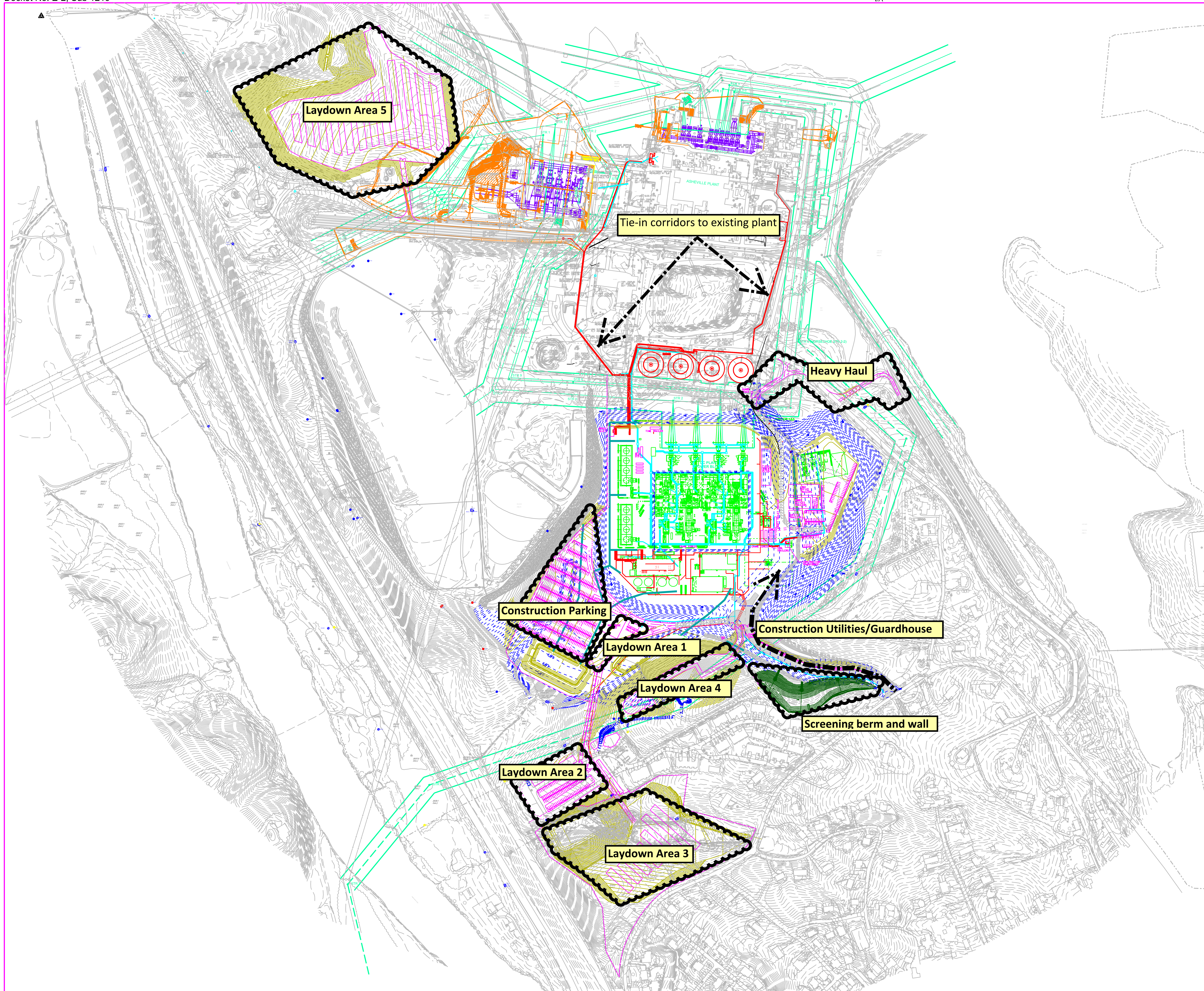
JOANN BUNZE, RPR

Notary Public #200707300112

Kerin Rebuttal Testimony
Exhibit 3
Page 1 of 1

LEGEND

- EXISTING TOPO AND EXISTING FEATURES
- PROPOSED TOPO FROM AMEC/FW AND BURNS & MCDONNELL
- PROPOSED TRANSMISSION R/W, STRUCTURES & LINES
- PROPOSED TOPO FOR CB&I CONSTRUCTION GRADING
- PROPOSED CB&I CONSTRUCTION FACILITIES
- PROPOSED POWER BLOCK
- PROPOSED CB&I PIPING
- PROPOSED CB&I ELECTRICAL ROUTES
- PROPOSED CB&I STORM WATER
- PROPOSED SCREENING BERM
- SWITCHYARD UPGRADES (BY OTHERS)



0 150' 300' 600' 900'
SCALE: 1" = 300'

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NC Eng. Firm Reg.#BUS.0125808
NC P.E. Firm #F-0946

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ASHEVILLE COMBINED CYCLE (ACC)
Arden, North Carolina

CLIENT DWG NO:

NOTES	REFERENCE DRAWINGS	NO.	REVISION	DRAWN	CK'D	APPD	DATE
		A	ISSUED FOR INFORMATION				

COMPOSITE FILE

FOR: Duke Energy Progress, LLC

DRAWN: | CK'D: | APPD: | DATE: | SCALE: 1"=300' | PROJECT NO: 205210 | DWG NO: ACC00-SK-C-SI-08 | REV: A

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing *List of Cross Exhibits* as filed in Docket No. E-2, Sub 1219A were served via electronic delivery or mailed, first-class, postage prepaid, upon all parties of record.

This, the 2nd day of October, 2020.

/s/Mary Lynne Grigg

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